EPCOR

EPCOR Natural Gas Limited Partnership

2021 Annual Gas Supply Plan Update (2020-2024 Gas Supply Plan)

Aylmer

EB-2021-0146

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1. Introduction

On October 25, 2018, the Ontario Energy Board ("Board") issued its Report of the Ontario Energy Board: Framework for the Assessment of Distributor Gas Supply Plans ("Framework") which set out a new requirement for all rate-regulated natural gas distributors in the Province of Ontario to file five year gas plans in January 2019. EPCOR Natural Gas Limited Partnership ("ENGLP") filed the Gas Supply Plan (Supply Plan) for the period 2019-2024 as part of the utility's cost of service application, in proceeding EB-2018-0336. The OEB in its Phase 1 decision approved the settlement proposal between the applicant and the intervenors in its entirety, including ENGLP's five-year GSP. In that proceeding, the OEB also approved the resulting cost consequences of the plan.

On May 1, 2020, ENGLP filed its 2020 annual update to the Supply Plan, in proceeding EB-2020-05-01. This document is the second Annual Update to the Supply Plan (the "Annual Update").

ENGLP has developed the Supply Plan in accordance with the criteria and guiding principles of (i) cost-effectiveness, (ii) reliability and security of supply and (iii) public policy, as defined in the Framework.

Guiding Principles for the Assessment of Gas Supply Plans

i. **Cost-effectiveness** – The gas supply plan will be cost-effective. Cost-effectiveness is achieved by appropriately balancing the principles and in executing the supply plan in an economically efficient manner.

ii. **Reliability and security of supply** – The gas supply plan will ensure the reliable and secure supply of gas. Reliability and security of supply is achieved by ensuring gas supply to various receipt points to meet planned peak day and seasonal gas delivery requirements.

iii. **Public policy** – The gas supply plan will be developed to ensure that it supports and is aligned with public policy where appropriate.

To satisfy the Framework requirements, ENGLP developed a demand forecast that reflects its expected annual load profile over the five year rate period starting January 2021. The demand forecast was used as an input in determining the appropriate mix between supply obtained from the Enbridge Gas system and local production.[1] To reliably meet forecasted Peak Day, seasonal, and annual demand, the supply strategy relies on the procurement of gas supply from local production as well as Enbridge Gas.

Applying the Framework's guiding principles of cost-effectiveness and reliability and security of supply, any incremental local gas supply will be assessed against the landed costs of natural gas supply alternatives to ensure this supply will be competitive with any alternative supply source for ENGLP's rate payer. This approach ensures that cost-effectiveness is balanced against reliability and security of supply, which considers flexibility and diversity in commodity procurement. The Supply Plan reflects the notion that cost-effectiveness is not paramount to reliability, or vice versa, rather the two principles are assessed together and the final supply option is a balance of the two principles to ensure that customers receive reliable supply which optimizes the cost-reliability function.

The objective of the Supply Plan is to develop a right-sized portfolio of natural gas supply assets that ensures consumers receive a cost-effective, reliable and secure natural gas supply in a manner that is consistent with public policy. The portfolio is designed to strike a balance between these guiding principles, which are consistent with the Board's legislated mandate to protect the interest of consumers with respect to prices, reliability, and the quality of gas service.

The Framework requires that, where appropriate, the Supply Plan supports and is aligned with public policy objectives. This includes the Federal Carbon Pricing Program, Renewable Natural Gas, and Community Expansion.

The Supply Plan is intended to provide strategic direction that will guide ENGLP's ongoing decisions related to its natural gas portfolio such that the utility is able to meet Peak Day, seasonal, and annual demand throughout the winter and summer periods

[1] Local production has been described in detail through ENGLP's QRAM and other proceedings. Local production refers to gas produced within ENGLP's franchise area or adjacent Lake Erie, i.e., onshore well gas, lake gas, or onshore renewable natural gas.

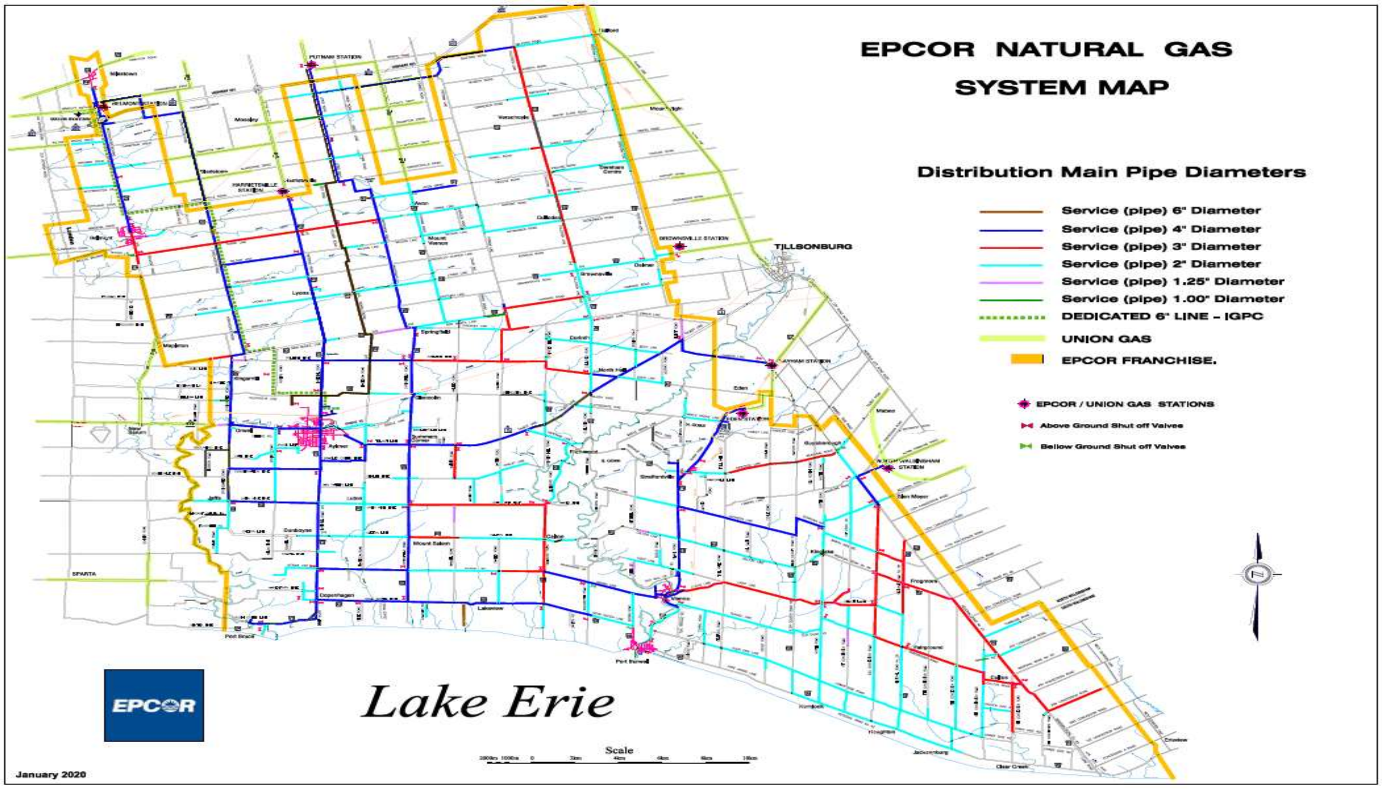
for General Service Customers and Contract Customers in a cost-effective manner. The plan does not commit ENGLP to procuring a set volume and/or source of natural gas, but rather provides a roadmap that is sufficiently flexible, such that reliable and cost-effective natural gas commodity and storage assets can still be procured in the event of changing or unexpected demand, consumption patterns, weather, or market forces.

ENGLP is presenting this Annual Update, including upcoming decisions in the Supply Plan, with the aim of being transparent and to enable meaningful consideration by the OEB. As the OEB pointed out in the Framework, "The responsibility for delivering reliable supply to customers in a prudent manner remains with the distributors. Distributors manage and execute their plans and adjust their activities to address changes to demand and supply conditions." Furthermore, ENGLP understands the Board's clarification in the Framework that "the assessment of the gas supply plans will not result in a decision on the costs or cost recovery. That would be the subject of related applications."[2] Accordingly, ENGLP understands that the Board's assessment of the Annual Update will not be an assessment of prudency, or an assessment of the cost consequences of the plan.

1.1. Summary of Service Area

The map below provides a summary of ENGLPs service territory which is current as of January 2020.[3] Key changes, relevant to the Supply Plan, include the addition of the 6 inch steel pipeline connecting off shore natural gas production to ENGLP's distribution system.

[2] EB-2017-0129, *Report of the Board*, dated October 25, 2018, at page 2.
[3] This map does not include the Village of Salford, a Certificae of Public Convenience and Necessity for this area was granted on January 16, 2020. The Village of Salford is proximate to the northeast corner of ENGLP's distribution system.



In 2021 EPCOR received OEB approval for a Certificate of Public Convenience and Necessity (CPCN) amendment to expand service into specific areas in South-West Oxford County, south of the Village of Salford to approximately 10 residential and commercial customers[4]. This expansion is not yet in service (expected fall 2021) but has been included in the forecast used in this update. There are not expected to be significant impacts as a result of this expansion.

1.2. Significant Changes

No significant changes were introduced this past year to Aylmer's Supply Plan.

[4] EB-2020-0232 Decision & Order, February 11, 2021

2. Demand Forecast

To develop a natural gas supply portfolio, ENGLP first constructed a demand forecast. The demand forecast for this Supply Plan is based on the values provided by Elenchus Research Associates Inc. ("Elenchus") in its Weather Normalization and Distributions System Load Forecast (EB-2018-0336, Exhibit 3, Tab 2, Schedule 1). This analysis was updated by Elenchus on April 17, 2021 for purposes of this gas supply plan. The forecast methodology can be found at the end of this section.

The utility will service three main classes of customers: General Service, Seasonal and Contract customers. These customers fit under six rate classes that include:

- **General Service Customers:** Rate 1 (General Service Rate) and Rate 4 (General Service Peaking),
- **Seasonal Customers:** Rate 2, and
- **Contract Customers:** Rate 3 (Special Large Volume Contract Rate), Rate 5 (Interruptible Peaking Contract Rate) and Rate 6 (Integrated Grain Processors Co-Operative Aylmer Ethanol Production Facility).

General Service Customers

General Service customers (residential, commercial, and industrial) are forecasted to make up approximately 28% of ENGLP's demand profile in 2020.

Residential customers make up the majority (69.9%) of the General Service demand profile. While the residential segment is expected to have the highest growth in terms of customer numbers (from 8,657 to 8,839), demand is expected to remain relatively flat in 2021 compared to 2020 weather-normalized demand. Commercial customers make up approximately 21.2% of the General Service demand profile. In 2021, 535 customers are forecasted to be under this segment. Both customer segments have flat, non-weather dependent demand requirements during the summer period (April to October), and heat-sensitive demand during the winter period (November to March). Industrial customers have an interruptible (Rate 4) and non-interruptible (Rate 1) component and make up approximately 14.73% of the General Service demand profile. There are 75 non-interruptible and 40 interruptible industrial customers in the ENGLP natural gas system forecasted for 2021.

Contract Customers

Contract customers are forecasted to make up approximately 69.5% of ENGLP's demand profile in 2021. There are currently 11 customers under this classification and no change in customer numbers are forecasted in 2021. At this time, Contract Customers contract for their own natural gas supply. Contract customer Rates 3 and 5 have an interruptible component and on average make up approximately 2.36% of ENGLP's demand profile by volume.

Seasonal Customers

Seasonal customer are forecasted to make up the remaining 1.47% of ENGLP's demand profile in 2020. There are 44 customers under this rate class and that consist mainly of tobacco framing and curing customers (non-interruptible).

The following Tables provide ENGLP's Customer Connection Forecast and Annual Customer Service Demand Forecast by Rate Class. The forecasted 2021 values are provided by Elenchus Research Associates Inc. ("Elenchus") in their Weather Normalization and Distributions System Load Forecast (EB-2018-0336, Exhibit 3, Tab 2, Schedule 1) and updated for purposes of this Annual Update. The updated Elenchus report can be found in Appendix D.

Table 2-1
Forecast of Customer Connections

	2020 Actual	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast
R1 Residential	8,839	8,839	9,102	9,415	9,769	10,133
R1 Industrial	75	75	77	80	83	86
R1 Commercial	535	535	548	562	576	591
R2 Seasonal	48	49	48	46	44	43
R3	6	6	6	6	6	6
R4	40	40	42	44	45	47
R5	4	4	4	4	4	4
R6	1	1	1	1	1	1
Total	**9,548**	**9,549**	**9,828**	**10,158**	**10,528**	**10,911**

Table 2-2
Forecast Annual Customer Service Demand, by Rate Class

	2020 Actual	2020 Normal	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast
R1 Residential	16,843,918	17,620,844	18,000,822	18,601,223	19,221,294	19,861,668	20,522,997
R1 Industrial	2,103,134	2,241,827	2,248,154	2,364,079	2,485,405	2,612,369	2,745,218
R1 Commercial	5,008,664	5,344,470	5,616,718	5,789,736	5,967,885	6,151,312	6,340,168
R2 Seasonal	785,475	785,475	1,305,829	1,261,308	1,218,305	1,176,768	1,136,647
R3	1,372,226	1,390,907	1,452,982	1,388,606	1,331,446	1,280,263	1,234,092
R4	1,556,748	1,556,748	1,792,148	1,952,899	2,128,069	2,318,951	2,526,955
R5	554,438	554,438	693,203	693,203	693,203	693,203	693,203
R6	59,599,950	59,599,950	59,599,950	59,599,950	59,599,950	59,599,950	59,599,950
Total	**87,824,554**	**89,094,659**	**90,709,805**	**91,651,004**	**92,645,557**	**93,694,483**	**94,799,231**

Methodology

The forecasted annual customer service demand for R1 Residential, R1 Commercial, R1 Industrial and R3 rate classes were determined through multivariate regressions. Consumption of the three R1 rate classes were forecasted using a base load and excess consumption methodology wherein average monthly consumption per customer was first calculated for each class. The amounts were then reduced by the base load consumption, which is considered the average consumption in the summer months of July and August. The remaining consumption is considered the weather-sensitive load (or “excess” load).

The excess load was regressed by the actual heating degree days in each month to determine the impact of cold weather on average consumption. A time-series (Prais-Winsten) regression was used to determine the coefficient, consistent with the methodology used in prior NRG throughput forecasts. Actual heating degree days were then multiplied by the coefficients and base load consumption was added back to determine the average predicted consumption in each month. Predicted total consumption of a class was determined by multiplying this sum by the actual number of customers. Similar methodology was used for the R3 rate class; however, the base load was removed from the regression.

Consumption of the remaining four rate classes (R2 Seasonal, R4, R5 and R6) were not weather- sensitive and did not exhibit sensitivity to the explanatory variables. Total and monthly volumes fluctuate from year-to-year and as such, a 5-year rolling average was used to forecast monthly consumption for each of these classes, with the exception of R4 in which a trend is also applied.

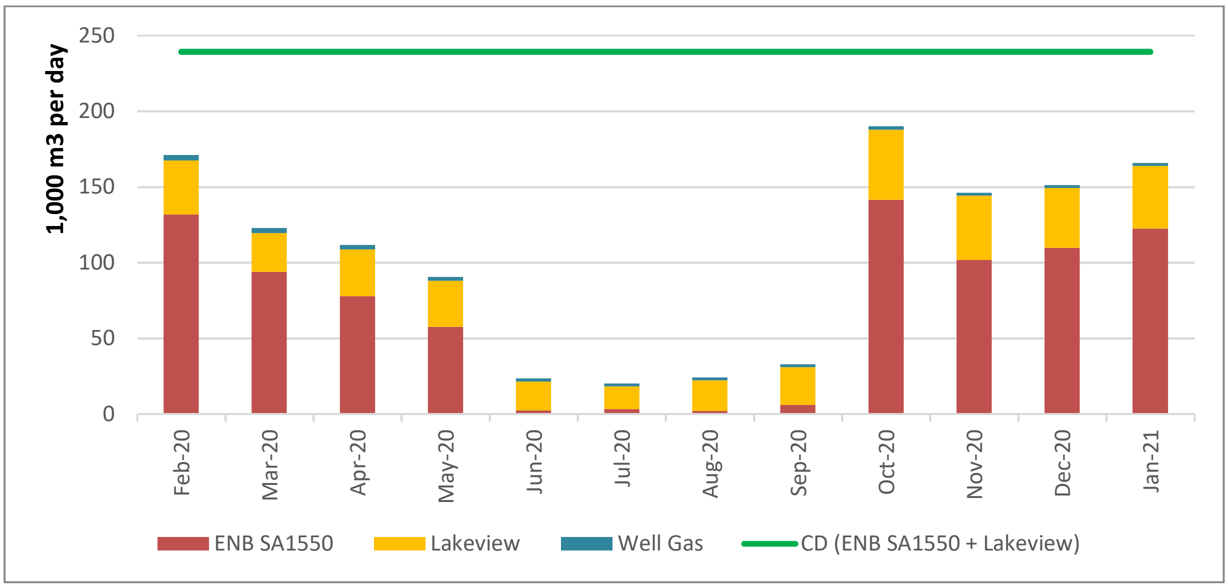
The customer connections count was forecasted by applying the geometric mean annual growth rate from 2010 to 2020 to the 2020 average customer count.

3. Supply Options

3.1. Key Assumptions

The appropriate balance of system gas supply and local gas production are considered for the procurement of natural gas commodity in order to meet the demand forecast established in Section 3. The chart below provides an analysis of the supply sources for the 2021 calendar year, including incremental local production.

Table 3-1
Max Daily Demand by Source vs Contract Demand, Feb 2020 to Jan 2021



While the demand forecast serves as the primary input used to develop the Supply Options, the following base assumptions also underpin each option:

3.1.1. Peak Day/Hour

ENGLP engaged Cornerstone to review and predict system conditions under the current peak gas demand and predict future peak demands. Based on the study, the biggest difficulty in establishing an accurate model for the distribution system was the loading throughout the system. Gas is not metered using district meter stations for each of the towns the system serves, which necessitates that a peak hour consumption estimate be developed for each town center. With the town loads making up a large majority of the consumption, based on the number of customers located in the towns compared to the distributed customers, this introduced a large unknown.

In previous analyses of this system's integrity, the month of November had days that were considered the peak scenario of gas consumption. In November, seasonal agricultural loads are still active and drawing gas from the system. The seasonal agricultural loads, however, are largely interruptible and therefore ENGLP focused on the January 2018 peak load, when seasonable interruptible customers were not using gas.

January 30, 2019 had the highest gas consumption for the historical data provided and the goal was to construct the base case model to reflect the gas meter readings that each Union station was seeing, as well as the pressure recordings at the stations and at the several other points in the system. The modelling was set up with flows in m^3/hour, so a peak hour was chosen for January 5, 2019 based on the hour with the largest meter readings (9:00 a.m.). The total meter readings for the 8:00-9:00 a.m. hour were 9,747 m^3/h, thus all loads had to equal that number.

This work provided ENGLP with a demand day road map in order to assist in determining the required Peak Day and firm Contract Demand requirements from its gas supply sources. The roadmap was updated in this Annual Update to include 2020 actual peak demand and a forecast for 2025.

Table 3-2
Actual & Forecast Demand Requirements

	ACTUAL / FORECAST	Actual and Forecast Peak Demand (Cornerstone)*	Actual and Forecast CD (Enbridge)	Lakeview CD (1,200 GJ/d)	Total CD
2016	ACTUAL	186,589	177,234		177,234
2017	ACTUAL	197,278	177,234		177,234
2018	ACTUAL	208,650	208,429		208,429
2019	ACTUAL	241,670	208,429	30,856	239,285
2020	ACTUAL	187,720	208,429	30,856	239,285
2021	FORECAST	251,434	220,578	30,856	251,434
2022	FORECAST	256,463	225,607	30,856	256,463
2023	FORECAST	261,592	230,736	30,856	261,592
2024	FORECAST	266,824	235,968	30,856	266,824
2025	FORECAST	272,160	241,319	30,856	272,175
*assume 2% growth YOY as per Cornerstone					

In 2020, the highest system gas peak day demand recorded was 187,720 m3 on October 30, 2020, which was below peak day demand in 2019. ENGLP will continue to monitor the system's consumption and growth pattern and increase contract demand from either Enbridge or Lakeview as needed.

3.1.2. Weather

ENGLP retained Elenchus to provide a Weather Normalized Distribution System Load Forecast. A copy of this report is provided in Appendix D.

3.1.3. Commodity

ENGLP receives the majority of its commodity under the bundled M9 rate which is based on Enbridge Gas' OEB approved WACOG application. ENGLP currently has three M9 Large Wholesale Service Contracts; SA1550 (System Gas) with a contract demand of 208,429 m^3, SA25050 (Direct Purchase) with a contract demand of 13,366 m^3 and SA8936 (IGPC) with a contract demand of 208,800 m^3.

The balance of ENGLPs commodity requirements are sourced from local production. Contracts the local production are described

3.1.4. Transportation

ENGLP incurs gas transportation costs (to/from Enbridge Gas) for storage, load balancing, and transportation across Enbridge Gas' system to ENGLP's distribution system. These costs are recovered in ENGLP's delivery charges as reflected in the EB-2018-0336 cost of service rate filing.

ENGLP currently contracts for an annual Contract Demand in the amount of 208,429 m^3 for its System Gas customers. ENGLP evaluates its Contract Demand requirements with Enbridge Gas on an annual basis and will balance the need to maximize its usage and minimize over run charges under this contract.

3.1.5. Storage

ENGLP relies on its contract with Enbridge Gas for storage, load balancing and transportation.

3.1.6. Daily Balancing Management

ENGLP is not required to Daily Balance its gas supply as that service is provided by Enbridge Gas under the M9 service agreement.

3.1.7. Direct Purchase Program

ENGLP has Direct Purchase Customers in its system whereby these customers arrange for gas supply and/or upstream transmission services directly with Enbridge Gas or ENGLP's distribution service to deliver gas to end-user locations. Currently, approximately 1% of ENGLP customers are on direct purchase compared to system sales and represent approximately 62% of ENGLP's demand profile by volume.

ENGLP relies on the Direct Marketer to deliver the volumes to Enbridge Gas. In accordance with the Bundled T-Service Receipt Contract between ENGLP and the Direct Marketer, if on any Day, for any reason, including an instance of Force Majeure, the Direct Purchase Customer fails to deliver gas then such event shall constitute a "Failure to Deliver" and the Failure to Deliver clause (Section 3.01) in the this contract will take effect. The Direct Marketer will indemnify and hold ENGLP harmless with respect to the excess of any costs and expenses incurred by ENGLP in acquiring such Gas and transportation capacity.

3.1.8. Long-Term Contracts

As noted in last year's annual update to the Supply Plan (EB-2020-0161), ENGLP signed a long-term (5 year) gas supply agreement with Lagasco on October 3, 2019, and the services commenced on December 1, 2019. The pricing terms of this contract are benchmarked to pricing available to ENGLP, specifically the M9 rate. This long-term ***firm*** supply contract will ensure any capital improvement projects identified in the capital plan that are undertaken to address system pressure issues are optimized.

Further, as noted in ENGLP Aylmer's Quarterly Rate Adjustment Mechanism ("QRAM") Application effective April 1, 2021 (EB-2021-0099), ENGLP entered into an Amending Agreement dated January 25, 2021 to the gas purchase contract for the local well supply (Production A and B) on a pricing mechanism similar to that paid for the incremental lake gas (Production C). Specifically, a 5% discount would be applied to the total gas supply commodity charge (inclusive of commodity rate adjustments) from Enbridge for all gas delivered to ENGLP, plus the Board approved delivery commodity charge paid to Enbridge.

Both the supply agreement for the incremental lake gas and the amending agreement for the local well gas will ensure there is sufficient gas supply in the Southeast area of the distribution system where ENGLP has historically suffered from low pressure issues that undermine security of supply. Pricing structure for both agreements ensure ENGLP's customer rates are not negatively impacted.

3.1.9. Diversity of Supply

Diversity of supply was identified as a key consideration in the Supply Plan. The introduction of incremental local production diversifies the portfolio as demonstrated in the analysis below:

Supply Source Breakdown-Forecast

	Enbridge	Production A & B	Production C	Total
2025	74.9%	1.1%	24.1%	100%
2024	73.9%	1.3%	24.8%	100%
2023	72.8%	1.6%	25.6%	100%
2022	71.7%	1.9%	26.4%	100%
2021	69.3%	2.3%	28.4%	100%

Supply Source Breakdown-Historical

	Enbridge	Production A & B	Production C	Total
2020	67.3%	3.3%	29.4%	100%
2019	94.9%	4.6%	0.5%	100%
2018	96.5%	3.5%	0.0%	100%
2017	94.3%	5.7%	0.0%	100%
2016	94.5%	5.5%	0.0%	100%

No significant changes are expected for this Annual Update.

3.1.10. Alternative Rate Consideration

In the 2020 Supply Plan update, ENGLP evaluated the economics of the M9 rate versus alternative rate offered – namely, the T3 and the M17. In the Staff Report dated December 14, 2020 (EB-2020-0106), OEB staff requests ENGLP to quantify the estimated net cost differential of the direct purchase option in this Annual Update. Using the most up to date rates, the table below shows the net cost differential for the M9, T3, and M17.

Table 3-3 Net Cost Differential (M9/T3/M17)

	M9	T3	M17
Annual Consumption (m3)	16,092,854	16,092,854	16,092,854
Contract Demand (m3/d)	208,429	208,429	208,429
Storage Allocation	N/A	Aggregate Excess Method	30% of Annual Consumption
Storage Cost	N/A	Cost Based	Market Based
Injection / Withdrawal rights	N/A	1.2% of MSB	1.2% of MSB
Nomination fee	N/A	Low	High
Administrative Cost	N/A	1 FTE	1.25 FTE
Premium to Dawn	**8%**	**17%**	**34%**

A number of assumptions were made in the analysis:

- Consumption volumes and daily contract demand were kept the same for all rate analysis scenarios, based on values forecasted for 2021

- For rates T3 and M17, storage allocation or contracted storage is required from Enbridge to manage supply procurement during the winter period. Storage allocation and Firm injection / withdrawal rights modeled for these rates follow the "Cost-Based Storage Space and Deliverability Allocation Methodology – Union South" Policies and Guidelines.[5] For the M17, ENGLP allocated storage based on 30% of the expected annual consumption.

- For incremental admin, ENGLP assumes varying levels of employee resources are needed for T3 and M17 to procure supply. In the Decision and Order for the ENGLP South Bruce QRAM dated September 24, 2020 (EB-2020-0206), the OEB agrees, while not determining the prudence of the cost, that incremental administrative cost is needed to administer the M17. Due to the unbundled nature of the T3, which also requires ENGLP to manage nomination, procurement, and storage injection / withdrawals on a daily basis, ENGLP also applies incremental administrative cost to the T3 analysis. The administrative cost is lower than that

[5] https://www.uniongas.com/-/media/about-us/policies/StorageAllocation_South.pdf

required for the M17, as with the T3 rate ENGLP would not need to manage the LBA.

From the analysis, both T3 and M17, which requires coordination of supply procurement and storage management, are costlier to manage than the M9. On a per-GJ unit cost basis, both the T3 and the M17 exceeds the 9% premium if supply were to be contracted at Dawn instead.

Furthermore, with the experience from South Bruce, due to the nature of the QRAM process, which requires a 12-month price forecast to construct the quarterly commodity rates, it will be likely that customer-facing commodity rates if ENGLP were to contract its own supply would be relatively similar to current system gas commodity rates for EPCOR South Bruce and Enbridge distribution areas – therefore, the increases in management cost incurred by ENGLP with these rate switches will likely be passed onto Aylmer's system gas customers.

4. Gas Supply Plan Recommendations

Given ENGLP's limited size and resources, the utility recommends it continue its strategy of contracting with Enbridge Gas for the M9 rate, including system supply. Local production, in particular the introduction of gas from Lake Erie, will augment Enbridge Gas' system supply in order to ensure reliability of the ENGLP system. Specifically, this incremental lake gas addresses historical low pressure issues and allows ENGLP to displace fixed price local production.

ENGLP is also developing the Southern Bruce natural gas franchise and as ENGLP gains operational experience and measures consumption data associated with this system, it will evaluate potential synergies between the two systems including the M9 system supply option for the Aylmer operation. ENGLP is mindful that should it elect to not take service under the M9 rate for the Aylmer operation, the rate will no longer be available to ENGLP.

5. Gas Supply Plan Execution & Risk Mitigation

5.1. Procurement Processes and Policies

Leading into each contract year (July for IGPC and November for Direct Purchase and System Gas customers), ENGLP will evaluate its current demand, its forecasted growth and direct purchase demand. This will help establish the annual Contract Demand with Enbridge Gas under each of the M9 contracts (System Gas Customers, Direct Purchase Customers and IGPC). ENGLP will also consider the amount of local production it is purchasing on both a firm and interruptible basis when establishing its Contract Demand with Enbridge Gas.

ENGLP has established a monthly review process with its System Gas and Direct Purchase Customers under Rates 3 and 5 to ensure provisions are in place for these customers to not exceed the established Firm Contract Demand. This will ensure the customers consume within the established Firm Contract Demand in the same manner that ENGLP has to operate within the limits set by Union. ENGLP established an annual review of its Rates 3 and 5 customers to ensure they are meeting the Minimum Annual Volume Requirements during each contract year as specified in the rate class descriptions.

Further ENGLP continues to review customer consumption to determine the appropriate rate class for each customer i.e. if their consumption is large enough to qualify for a contract rate. This review will also be conducted if there is a significant change in consumption (volume or profile) of an existing customer.

ENGLP completed an annual review of the Residential accounts at the end of December 2020 and re-classified those customers that should have classified as commercial or industrial.

5.2. Evaluation of Procurement Process and Policies

ENGLP purchases the majority of its commodity from Enbridge Gas. ENGLP does not directly enter into upstream transportation, daily balancing, and seasonal storage or third party commodity agreements and therefore does not establish contracting policies with respect to these services.

ENGLP procures a number of other gas related services including consulting services such as those provided by ECNG Energy LP. These other services are initiated through a Request for Proposals (RFP) process provided through a Shared Services Agreement with EPCOR Water Services Inc. (EWSI), an Edmonton-based corporation. The RFP process is governed by a Procurement Document which provides guiding principles; non-competitive procurement procedures; approvals and limits; roles and responsibilities; and compliance.

As part of its Annual Distribution Capital Planning Process[6], ENGLP reviews the system's peak day requirements and ensures it has sufficient assets and contracting flexibility in order to meet these requirements. These capital plans are filed as part of the EB-2018-0336 Cost of Service rate filing.[7] Contract considerations include:

- The amount of firm Contract Demand capacity required from Enbridge and local producers; and
- The amount of interruptible capacity contracted for under Rate 5 – Interruptible Peaking Contract.

These plans are reviewed annually and subject to oversight by EPCOR Utilities Inc.'s Board of Directors.

5.3. Risk Mitigation Strategy

A key aspect of the execution of this Gas Supply Plan is the identification of risks and the adoption of risk mitigation strategies.

5.4. Description

The risks identified are:

1. M9 Rate no longer being offered by Enbridge; and

[6] This process is subsumed within the "Utility System Plan" evidence of the EB-2018-0336 Cost of service rate filing.
[7] EB-2018-0336, Application and Pre-filed Evidence, Exhibit 2, Tab 3, Schedule 1, at page 2.

2. Accelerated depletion of local gas production wells.

5.5. Evaluation

M9 Rate no longer being offered

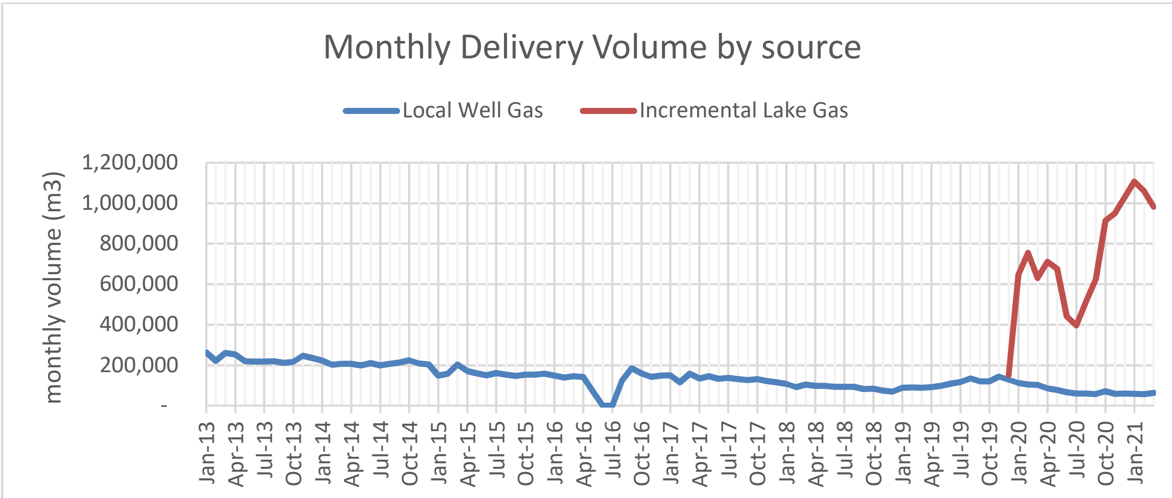
ENGLP is aware that Enbridge Gas has an approved new M17 rate designed to provide transmission service to embedded distribution utilities. ENGLP's view is that this new rate is unfavorable as compared to the M9 rate and does not intend to subscribe to this service. The OEB recently ruled that any embedded distributor who elects to move to an M17 rate will be precluded from returning to its former M9 rate. However, as the Board indicated in its decision on Enbridge's M17 application, ENGLP understands that Enbridge will continue to offer the M9 rate to ENGLP (Aylmer). As discussed in this Gas Supply Plan, ENGLP (Aylmer) intends to stay on the M9 rate.

5.6. Accelerated depletion of local gas production wells

ENGLP retained GSA Energy to identify the remaining production life of the former NRG Corp. wells, as part of its acquisition of NRG. GSA Energy's review identified the significant economic depletion in the remaining production life of NRG Corp.'s wells.

The graph below shows the monthly local production volumes since 2013.

Figure 5-1 – ENGLP Aylmer Monthly Local Production



ENGLP consulted with Lagasco in order to determine production levels over the planning period. Lagasco confirmed production will continue to decline from these wells. In 2020, Well gas volumes declined by another 31% compared to 2019 volumes. To mitigate potential gas shortages in the South area of the franchise[8], ENGLP contracted for incremental lake gas starting December 2019 on a firm basis. Between December 2019 and March 2021, the incremental lake gas contract delivered 11,592,312 m3 of gas into the distribution system. As the graph above shows, the new incremental lake gas supply volume is more than sufficient in offsetting declines in local well gas volumes. ENGLP will continue to monitor performance of this incremental supply source.

[8] EB-2018-0336, Application and Pre-filed Evidence, Exhibit 2, Tab 3, Schedule 1, page 15-16.

6. Public Policy Objectives

6.1. Renewable Natural Gas (RNG)

ENGLP understands and supports the development of an RNG market and facilitates inclusion of RNG in its gas supply portfolio. ENGLP recognizes the importance of Greenhouse Gas (GHG) abatement across the province, as well as the role that ENGLP plays in supporting the achievement of GHG emission reduction targets.

At this time, ENGLP does not hold any RNG supply in its Supply Plan. However, ENGLP is currently in discussion with customers capable of providing RNG into the natural gas distribution system. ENGLP will update the Supply Plan as strategies of a RNG solution are developed and finalized.

6.2. Demand Side Management (DSM)

ENGLP is in process of developing a commercial DSM pilot expected to be rolled out in 2021 or 2022. If proved to be successful, ENGLP would look to expand the DSM offerings into other rate classes. ENGLP has been working with OEB staff to better understand the DSM framework and budgetary expectations. Customer rate impacts and uptake will be key drivers of the success of the pilot and future DSM program.

6.3. Community Expansion

ENGLP has been actively working to bring secure, reliable and affordable natural gas to unserved communities. A number of customers have requested service and ENGLP has pro-actively responded to those requests.

In 2020, ENGLP received approval from the OEB to serve the community of Salford[9] and to serve three individual ex-franchise customers lying along traversing pipelines.[10,11] ENGLP applies the guidelines as set out in EBO 188 to ensure there is no cross-subsidization between existing and potential new customer connections.

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[9] EB-2019-0232, Decision and Order, dated January 16, 2020.
[10] EB-2017-0108, Decision and Order, dated August 15, 2019.
[11] EB-2017-0108, Decision and Order, dated September 13, 2019.

As noted in section 1.1, in 2021, ENGLP received approval from the OEB for an amendment to the current CPCN to connect additional commercial and residential customers in South-West Oxford County (south of the village of Salford).[12]

6.4. Federal Carbon Pricing Program

As part of the Government of Canada's Federal Carbon Pricing Program ("FCPP"), a federal carbon pricing system has been implemented in Ontario, under the *Greenhouse Gas Pollution Pricing Act,* with the following features:

For larger industrial facilities, an output-based pricing system for emissions-intensive trade-exposed ("EITE") industries applied in January 2019. This will cover facilities emitting 50,000 tonnes of carbon dioxide equivalent ("CO2e") per year or more, with the ability for smaller EITE facilities that emit 10,000 tonnes of CO2e per year or more to voluntarily opt-in to the system; and,

A charge applied on applicable fossil fuel deliveries, as set out in the *Greenhouse Gas Pollution Pricing Act*, Part 1, effective April 1, 2019.

As part of ENGLP's compliance requirements with respect to the FCPP, the utility filed its 2019 FCPP application (EB-2019-0101) with the Board on March 8, 2019. The application was approved on July 18, 2019.

In 2020, ENGLP filed two subsequent applications for 2020 and 2021 FCPP rates, which were approved in March 2021.[13]

[12] EB-2020-0232, Decision and Order, dated February 11, 2021.
[13] EB-2020-0076 / EB-2020-0231, Decision and Order, dated March 11, 2021.

7. Current and Future Market Trends Analysis

ENGLP engaged ECNG to perform a “Current and Future Market Trends Analysis”. This analysis can be found in Appendix “A”.

In summary, the Current and Future Market Trends Analysis, concludes there are no major changes expected in the North American natural gas market over the planning period that will shift the fundamental supply and demand dynamics to a degree that will impact the viability of the Supply Plan and its ability to deliver on the guiding principles of cost-effectiveness and reliability and security of supply.

8. Performance Metrics

In last year’s Supply Plan update, ENGLP drafted a performance metric scorecard in order to measure the effectiveness of the Supply Plan. The updated Scorecard can be found in Appendix E. Note that while the premium on the well gas in 2020 was comparatively high compared to Enbridge system supply on a percentage basis, the volume of well gas was only 3.3% of annual supply volume in 2020. In October of 2020, the new Amending Agreement for the local well supply will be priced at a discount to the Enbridge system supply cost, which will bring the price of the local well supply much closer to the Enbridge system supply cost.

9. Continuous Improvement Strategies

The continuous improvement to the supply planning process undertaken by ENGLP is an important element of the transparency objective of the Framework. ENGLP continues to proactively evaluate new supply and transportation options in accordance with the Framework's guiding principles.

ENGLP will also continue to proactively identify new opportunities to meet its gas supply obligations while meeting the Framework assessment criteria. ENGLP will also continue to review and improve the information it receives for market outlook and forecasting purposes.

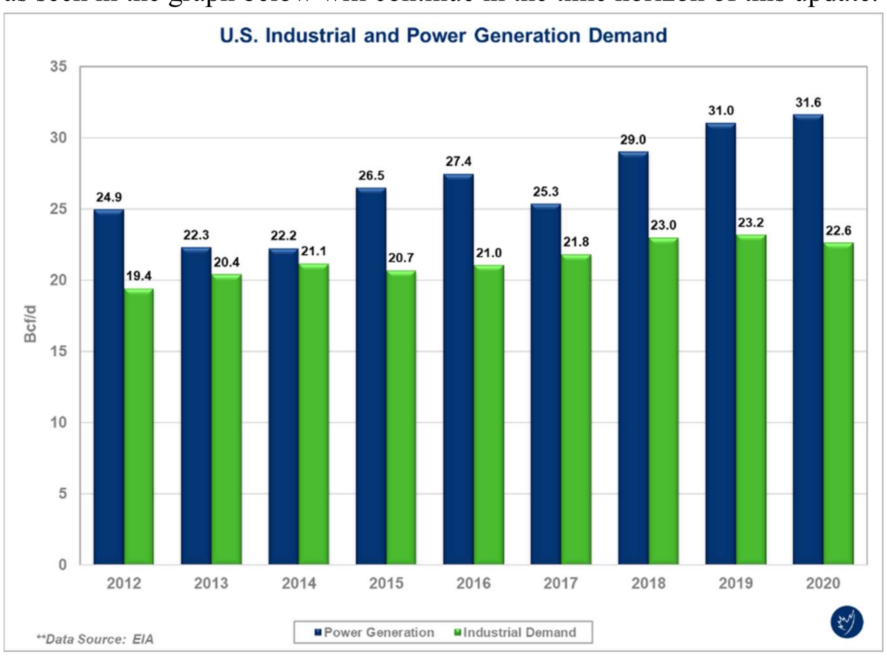
ENGLP expects to commence service to customers in its Southern Bruce franchise area in 2020. There may be opportunities to combine gas supply plans for both the Aylmer and Southern Bruce areas but ENGLP believes that at this time, this opportunity is beyond the scope of this gas supply planning period.

10. Appendix A – Market Trends Analysis April 2021 Update

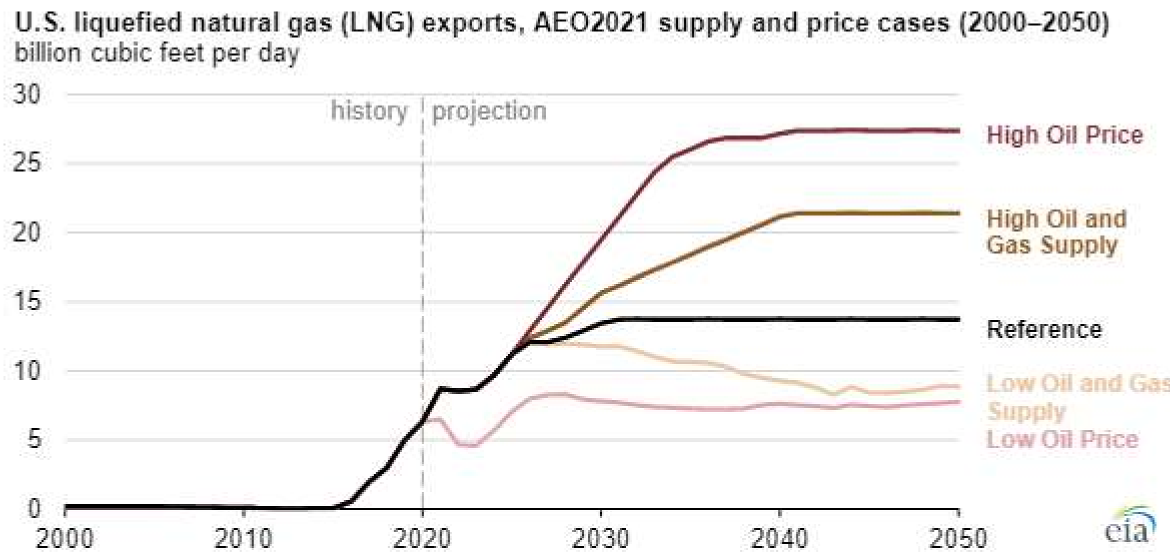
Current and Future Market Trends Analysis
Provided by ECNG

As an element of the risk mitigation strategy, the following overview of current and future trends is intended to inform EPCOR of any changes in natural gas market fundamentals which have the potential to impact its ability to execute the Supply Plan. The North American fundamental drivers for natural gas are demand, supply, storage and in a more limited/indirect way crude oil and underlying currency foreign exchange. "Near-term" is within the next 12 months, "Mid-term" is 1-2 years after Near-term, "Long-term" is 3-5 years after Mid-term.

Demand: Impact on pricing – Near-term Mildly Bullish, Mid and Long-term Mildly Bullish
The 2020/2021 Winter weather overall, across most of North America (N.A.) resulted in lower than average demand in the residential, commercial and industrial sectors. Mid-term and Long-term gas demand growth is largely expected by most forecasters post pandemic in the United States (U.S.) in Industrial and gas fired power generation demand sectors. The federal government change in the U.S. with a mandate to battle climate change translates into an expectation to continue having gas fired generation running more baseload hours fueling with natural gas further pushing out coal. The U.S. Energy Information Administration's (EIA) Annual Energy Outlook 2021 (AEO2021) cites an expectation of increasing consumption of natural gas and electricity. The expectation is that modest growth as seen in the graph below will continue in the time horizon of this update.



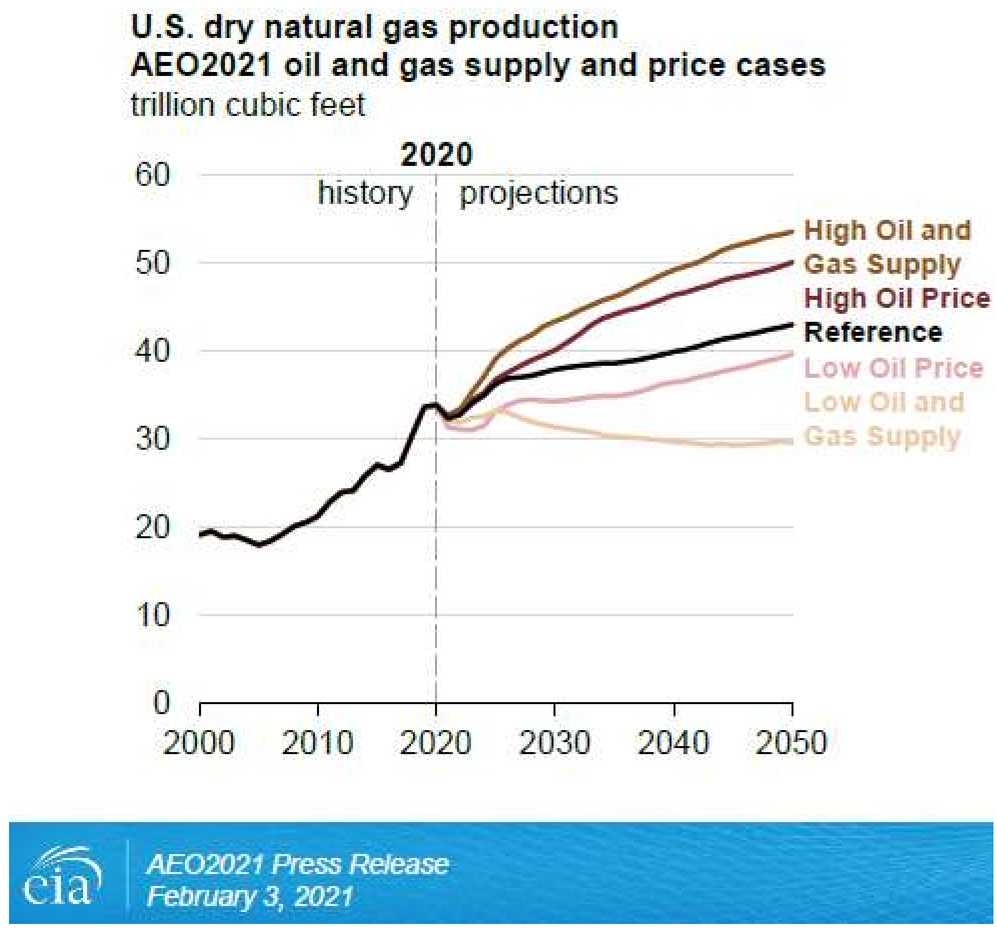
The LNG export chart below is from the EIA AEO2021. The various scenarios show a dramatic range of outcomes however ECNG's view is that Reference case will prevail in the Mid-term. In the Reference case, LNG exports continue to grow throughout the 2020s, reaching 13.7 Bcf/d by 2030 which requires only one or two (of many projects which already have FERC construction approval) to reach a positive Final Investment Decision later in 2021.
U.S. LNG exports including fuel gas for refrigeration are now operating at near capacity between 11 and 12 Bcf/day in early 2021. This will continue to be a significant contributor to a tight supply-demand balance in N.A.



Also increasing demand for U.S. supply is Mexico. Expectations for exports to Mexico during this outlook's horizon could see average exports to Mexico well exceed 7 Bcf/d from the current flows of 5-6 Bcf/d. This increased demand is mostly for power generation and growth would require increased pipeline infrastructure. Mexico has the capability to receive LNG cargoes, and this will bolster increased demand from the U.S. Finally, in the Long-term, Mexico may become a conduit for U.S. pipeline access (increased exports) to Mexico's Pacific coast to shorten LNG routes to Asia.

Supply: Impact on pricing – Near-term Mildly Bullish (NYMEX) and Mildly Bullish (AECO); Mid and Long-term Mildly Bearish (NYMEX) and Bearish (AECO)

While year over year U.S. dry gas production (supply) growth has been impressive in 2018 and 2019, 2020 was setback mostly due to the pandemic - uncertainty in demand led to prompt month's price softening which then led to reduced investment by producers. The EIA's Reference case is forecasting a slow return to 2019 levels by 2023 in its reference case, see below. The EIA also expects supply to be able to satisfy growing demand at current prices.

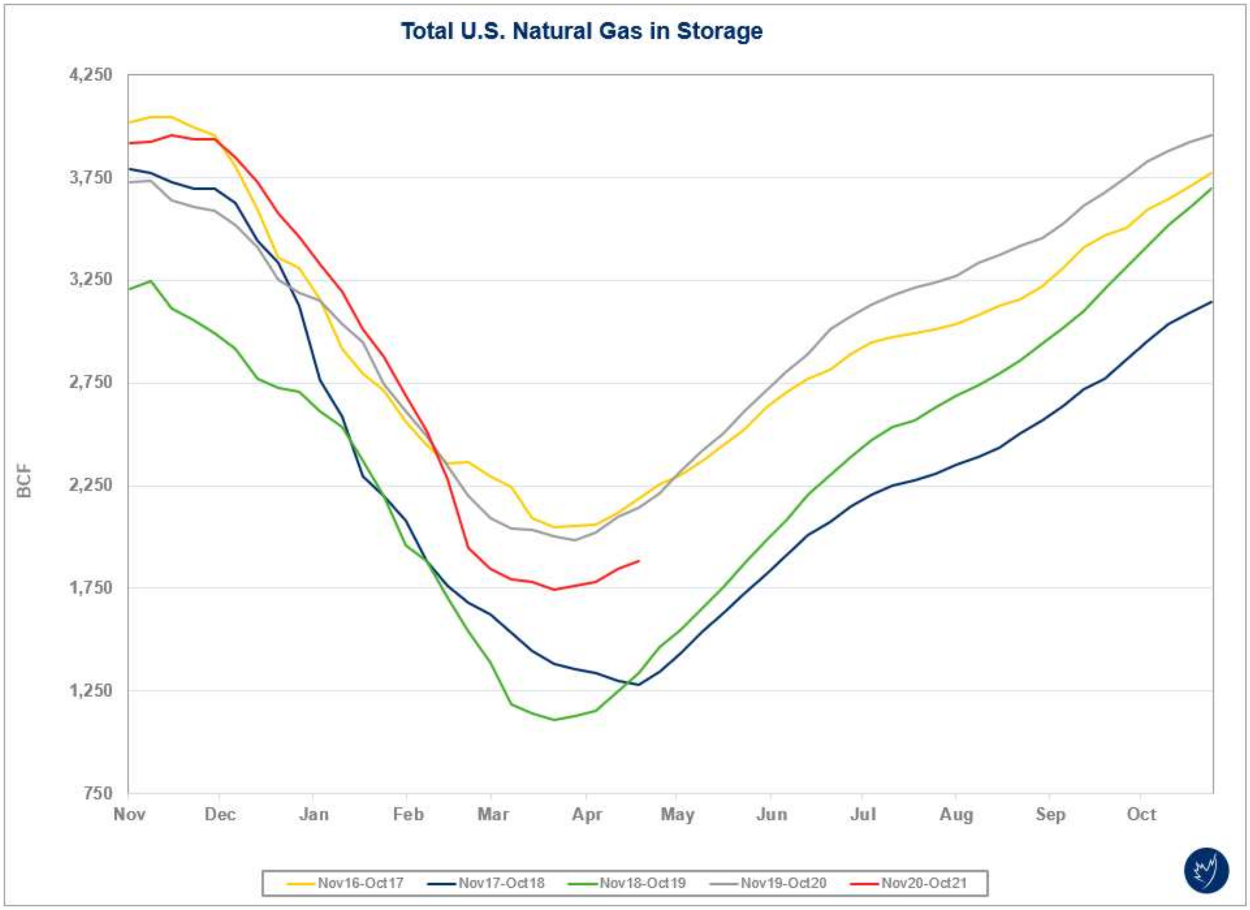


The Western Canadian Sedimentary Basin (WCSB) production is expected to grow modestly with timing dependent on market access being provided to the remote shale deposits in NE BC and NW AB. Early 2021 saw an increase in US exports to help meet the unexpected cold weather in mid-continental U.S. which was largely met by Western Canadian storage withdrawals and not by production growth. Nova Gas Transmission Ltd. (NGTL) is nearing its completion of its $6.7 billion renovation and expansion program however not likely until late in 2022 or early 2023 due to COVID-19 protocols and some regulatory approvals that have not yet been fully granted (however still expected). WCSB continues to be poised to grow however transportation to markets outside of BC and AB are key to that growth and are dependent on contract renewals and possible toll negotiations to maintain and/or grow current flows.

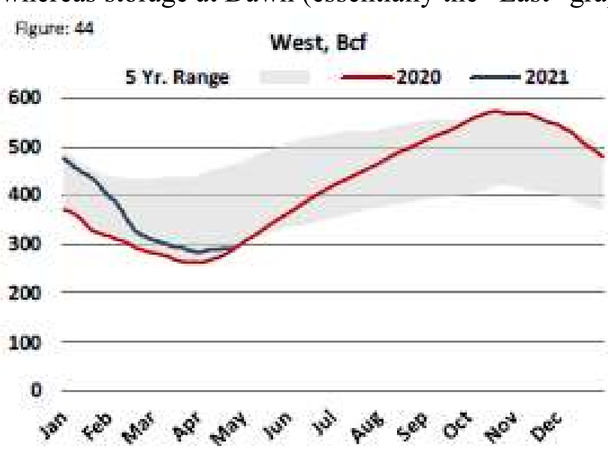
At current elevated prices relative to last year, the supply response has been slow in U.S. and in Canada which may show that producers are less willing to grow production with financial leveraging and more through cashflow. This sentiment is driving the bullish sentiment in the short run. Mid and Long-term there is little disagreement that there are ample N.A. reserves to meet the demand forecasts.

Storage: Impact on pricing – Near term Mildly Bullish (NYMEX and Dawn), Bullish (AECO); Mid and Longer-term No Impact on price

Total U.S. working inventories on March 31, 2021 fell just below the five-year average of 1.8 Tcf. Most industry forecasters see end of injection season ending significantly less than 2020's value of nearly 4.0 Tcf. The likely outcome has storage filling 0.4 to 0.5 Tcf less than last year or about 2 to 3 Bcf/d less supply available in the upcoming winter. This may also lead to an inventory level at the end of the upcoming winter season significantly less than the 5 year average and possibly reaching a new 5 year low.



In Canada, storage at winter's end in Alberta (essentially the "West" graph below) is near last year's 5 year low, whereas storage at Dawn (essentially the "East" graph below) is closer to the 5 year average.



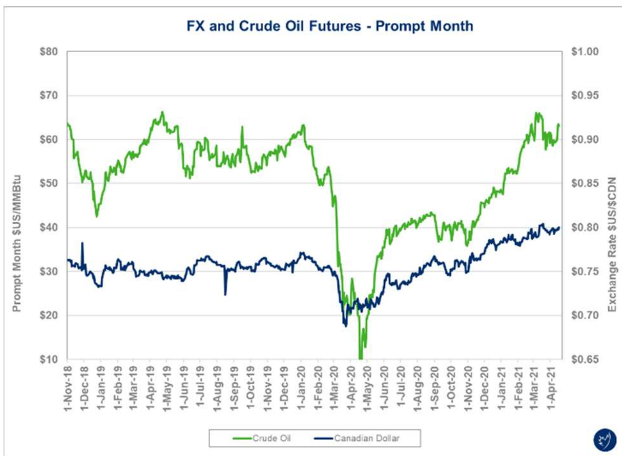
Storage graphs from RBN Energy LLC 2021 at April 28, 2021.

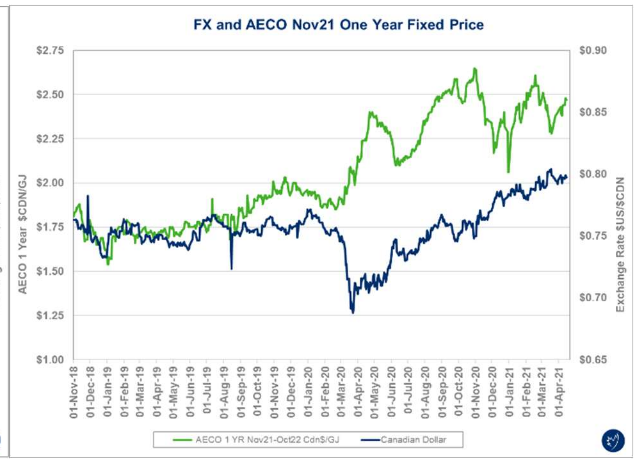
All these current storage balances lead to a more bullish sentiment on gas pricing year over year as it either increases summer demand (US and Eastern Canadian) or maintains demand (Western Canadian) to refill.

Crude Oil and Foreign Exchange: Impact on NYMEX and Dawn pricing – Near-term Mildly Bearish, Longer-

term Neutral; Impact on AECO pricing Neutral Near and Longer-term

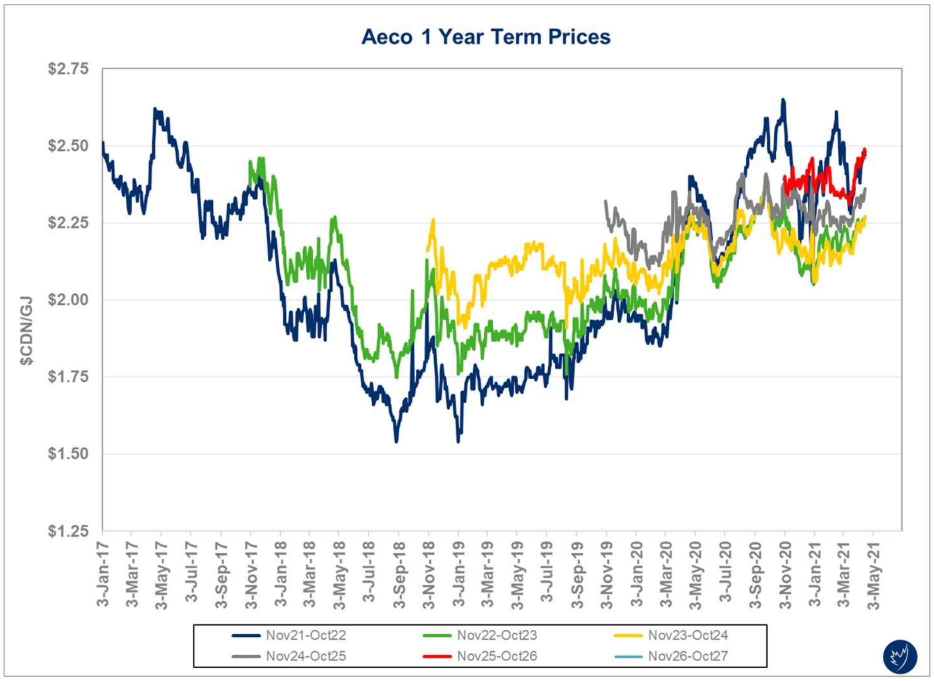
World oil pricing in early 2021 has remained supported in the $50-60 USD/barrel price range with supply being managed by OPEC and Russia during most of the pandemic after a crash landing and restart in April 2020. Associated transportation fuels demand around the globe has seen the largest decline due to stay-at-home mandates instituted to fight the spread of COVID-19. ECNG's view is oil pricing will remain at these price levels supported by pent up travel demand as the pandemic subsides which will continue to return associated gas supply to pre-pandemic levels. With higher oil pricing the Canadian buyer should enjoy a stronger dollar which will offset the higher price of NYMEX priced gas (which mostly drives Dawn pricing). The next two graphs show the relationship of crude oil pricing and the U.S./Canadian foreign exchange (FX) and FX on the price of gas in the WCSB (AECO). It appears the strength in FX since mid-2020 has not contributed much to a lower AECO price which is good news for the Canadian producer and good news for the gas buyer at Dawn.





Near-term Summary – Mildly Bullish (NYMEX and Dawn), Bullish (AECO)

In the U.S., strong LNG exports, lower inventories (in the U.S. and at Dawn) at winter's end, with only similar supplies to 2019 supplies make for a tight supply-demand market. As a result, NYMEX and Dawn price outlooks in the short term are at risk especially to a warmer than average summer or a colder than average winter. The forward Dawn price for 2022 has similar volatility risk to the forward 2021 price shown in the graph below. AECO pricing is expected to stay strong and move with or go narrower to NYMEX with a larger year over year regional storage deficit supporting its pricing. Current forward pricing history is found below.



Mid to Long-term Summary – NEUTRAL (NYMEX and Dawn), Mildly Bearish (AECO)

In the U.S. the expectation of continued strong LNG exports, post pandemic return to economic growth, continued fuel of choice in power generation and a return to shale gas supply growth (including supply from oil production) we expect pricing to move modestly upward. The landed cost of gas at Dawn is between approximately $2.90 and $3.10 CAD/GJ for the next 4 gas years. This is good value and in a couple of years we do expect prices to move higher if U.S. natural gas production is unable to respond in 2021 at current forward price levels. Conversely forward pricing at AECO is at recent historic highs which in our view should lead to future supply exploration and development to certainly fill up the increased delivery infrastructure in progress for completion sometime in 2022. As a result, we are looking for AECO prices to have the potential to weaken heading into early 2023.

Dawn Market Hub Discussion

Natural gas primarily flows into the Dawn Hub ("Dawn") from the WCSB and from the U.S. Marcellus and Utica shale plays in the Appalachian region as well as from the Chicago Citygate (a market Hub with excess supply from WCSB and other U.S. supply regions). There are no new projects expected in the Dawn connected infrastructure over the planning period that will shift the fundamental supply and demand dynamics to a degree that will impact the viability of the Supply Plan. With its multiple pipeline connections to the largest supply basins in N.A. providing supply reliability and access the Dawn market can be vulnerable to pipeline contracting, renewals and long-term toll negotiations between pipelines and its shippers (suppliers, distribution utilities, marketers and large industrial buyers). Within the next 5 years, some long-term contracts will expire or may be reopened and may not be renewed under the same terms. This change in contracting can change the flow dynamics into and out of Dawn which will influence the price of gas there. Despite these potential undercurrents, the Gas Supply Plan is expected to be able to deliver on the guiding principles of cost-effectiveness, reliability and security of supply.

11. Appendix B – ECNG Credentials

ECNG Energy Group

ECNG Energy Group is Canada's largest full-service energy management consultant that works exclusively for the end-user in contracting for natural gas and electricity supply as well as delivery services. Further, we provide complete solutions ranging from energy conservation to electricity generation. We manage a volume of approximately 150,000 gigajoules per day of natural gas and 2.5 billion kilowatt hours annually on behalf of our clients, making ECNG the largest purchaser, other than the major utilities, in Canada. The advantages of retaining ECNG are access to specialized in-depth industry expertise, encompassing day-to-day market knowledge, utility rate options, existing regulatory framework, impending changes in these ground rules, and contact with a wide range of reliable gas suppliers.

ECNG's fees are fully transparent. At no time does ECNG take title to supply nor do we receive supplier kickbacks on any natural gas or electricity supply procurement transactions. The client always pays the true cost as offered by the supplier with zero margins being given back to ECNG. This ensures we always achieve the utmost competitive and transparent pricing while providing end-use consumers with objective and expert energy advice.

ECNG has been in business since 1987 and has built a large and loyal client base, including many of Canada's leading corporations, retailers, healthcare providers and associations. Our service to these clients includes over 21,000 end-use locations in all deregulated jurisdictions across the country. With this scale of operation, ECNG receives virtually every cost saving proposal from the supply and transportation communities. Finally, economies of scale and scope permit ECNG to provide its services at a fee that is a small fraction of the delivered cost of your energy. Additional information is available by visiting our web site www.ecng.com.

ECNG PRINCIPALS CVs

Angelo P. Fantuz – Director, Client Services

A Professional Engineer, Angelo brings 35 years of experience to his current role advising Canada's large commercial and industrial end-users about natural gas and electricity procurement and developing procurement strategies for clients. Angelo and his team are also responsible for monitoring regulatory development in order to ensure ECNG and its clients are prepared for what's ahead. Prior to joining ECNG in 2003, Angelo held senior roles at Eastern Pan Canadian/EnCana and Union Gas Limited. While at Union Gas he was a key sponsor in the development of Gas C.A.R.E. relational database to track, control and schedule the gas flow between Union Gas and its interconnected pipelines. He also testified at the Ontario Energy Board defending gas costs embedded in customer rates.

Dave Duggan – Director, Energy Supply & Market Risk

One of Canada's leading authorities on energy commodity purchasing and market fundamentals, Dave is a respected thought leader. He has shared his expertise and understanding of the Ontario and Alberta power markets and Eastern and Western Canada natural gas markets at various conferences presenting multiple times at EMC's Future of Manufacturing Conference, BOMA Canada's BOMEX – Canada's Building Excellence Summit and other conferences. Since 1995, he has held various senior leadership roles within ECNG and executed thousands of natural gas, power and transportation hedge purchases. He is currently responsible for setting market strategy and leading the Energy Commodity Supply and Price Risk Management team, which procures natural gas and electricity supply for utilities, institutional, commercial and industrial clients across Canada. Dave and the team collect and assess market intelligence and conduct fundamental analysis and financial modeling of risk management strategies for natural gas and electricity.

Paul Weingartner – Director, Client Services

Paul is both a Certified Energy Manager and Certified Energy Auditor with almost 20 years' experience building Canada's largest direct-purchase programs across multiple industries. He is a subject matter expert and speaker for organizations such as: the Canadian Healthcare Engineering Society, where he currently serves as Chair of its Corporate Advisory Council; the Independent Electricity System Operator; and Natural Resources Canada, among others. He joined ECNG Energy Group in 2008 after managing national energy programs for HealthPRO Procurement Services. Paul is responsible for managing ECNG's largest clients, developing and implementing customized multi-pronged commodity hedging strategies designed to meet their unique needs and bringing added value by identifying opportunities in the highly complex and volatile natural gas and electricity markets.

Steve Williams – Senior Energy Analyst, Supply & Risk Management
Steve has a deep understanding of the complex Canadian natural gas and power markets, from pricing to storage to logistics and more. He analyzes the markets to transact cost-effective natural gas and power deals in Ontario and Alberta. Steve's training as an accountant informs his detailed approach and helps ECNG's clients create impactful commodity strategies. He joined ECNG in 2007 after building his career in finance at Horizon Utilities and Burlington Hydro.

Althea Rothwell, Senior Consulting Analyst
Althea Rothwell has over 20 years of industry experience ranging from pipeline maintenance to operational controls. Working closely with utilities, pipelines and customers, Althea maintains high standards in meeting operation, supply and utility objectives. Drawing on past experience within the Accounting and Financial Trades sector, Althea provides detailed and accurate reporting to clients regarding contracted financial and volumetric balancing of natural gas.

12. Appendix C - Detailed Supply/Demand Forecast

SUPPLY FORECAS TANALYSIS													
Production A and Production B (Formerly NRG now owned by Lagasco)													
	January	February	March	April	May	June	July	August	September	October	November	December	Total
2025	33,914	33,462	33,016	32,576	32,141	31,713	31,290	30,873	30,461	30,055	29,654	29,259	378,415
2024	39,842	39,310	38,786	38,269	37,759	37,255	36,759	36,269	35,785	35,308	34,837	34,373	444,552
2023	46,805	46,181	45,565	44,958	44,358	43,767	43,183	42,607	42,039	41,479	40,926	40,380	522,249
2022	54,985	54,252	53,529	52,815	52,111	51,416	50,731	50,054	49,387	48,728	48,079	47,438	613,525
2021	58,255	57,616	62,884	62,046	61,219	60,402	59,597	58,802	58,018	57,245	56,481	55,728	708,295
												Decline Rate	16%
Enbridge (Supply)													
	January	February	March	April	May	June	July	August	September	October	November	December	Total
2025	4,443,242	3,813,119	3,158,810	2,057,059	865,734	320,459	443,113	635,892	711,002	2,163,609	4,033,710	3,705,014	26,350,762
2024	4,271,313	3,677,850	3,031,478	1,952,613	830,160	283,174	404,250	605,740	677,108	2,040,114	3,823,113	3,582,963	25,179,877
2023	4,105,536	3,546,558	2,908,048	1,851,449	794,790	246,468	366,167	576,525	645,123	1,924,034	3,623,853	3,464,704	24,053,254
2022	3,945,624	3,419,072	2,788,338	1,753,341	759,497	210,156	328,652	548,056	614,825	1,814,732	3,435,110	3,350,022	22,967,425
2021	3,642,125	3,106,555	2,646,790	1,658,057	724,144	174,032	291,476	520,122	585,983	1,711,605	3,256,115	3,238,718	21,555,722
Production C - (Lakeside Production owned by Lagasco)													
	January	February	March	April	May	June	July	August	September	October	November	December	Total
2025	956,784	864,192	956,784	655,920	478,392	462,960	299,832	299,832	655,920	956,784	925,920	956,784	8,470,104
2024	956,784	864,192	956,784	655,920	478,392	462,960	299,832	299,832	655,920	956,784	925,920	956,784	8,470,104
2023	956,784	864,192	956,784	655,920	478,392	462,960	299,832	299,832	655,920	956,784	925,920	956,784	8,470,104
2022	956,784	864,192	956,784	655,920	478,392	462,960	299,832	299,832	655,920	956,784	925,920	956,784	8,470,104
2021	1,112,320	1,058,999	982,175	655,920	478,392	462,960	299,832	299,832	655,920	956,784	925,920	956,784	8,845,838
Total Supply – Production A + B (Formerly NRG) + Enbridge Gas + Production C (Lakeshore)													
	January	February	March	April	May	June	July	August	September	October	November	December	Total
2025	5,433,941	4,710,773	4,148,610	2,745,555	1,376,267	815,132	774,235	966,597	1,397,383	3,150,448	4,989,285	4,691,057	35,199,281
2024	5,267,939	4,581,353	4,027,049	2,646,802	1,346,311	783,389	740,840	941,841	1,368,813	3,032,206	4,783,870	4,574,120	34,094,533
2023	5,109,125	4,456,931	3,910,397	2,552,327	1,317,540	753,195	709,182	918,965	1,343,082	2,922,297	4,590,699	4,461,868	33,045,607
2022	4,957,393	4,337,517	3,798,651	2,462,076	1,290,000	724,532	679,215	897,942	1,320,132	2,820,245	4,409,109	4,354,244	32,051,054
2021	4,812,701	4,223,170	3,691,849	2,376,023	1,263,755	697,394	650,905	878,757	1,299,921	2,725,634	4,238,517	4,251,230	31,109,856
DEMAND FORECAST ANALYSIS													
Total Demand													
	January	February	March	April	May	June	July	August	September	October	November	December	Total
2025	5,433,941	4,710,773	4,148,610	2,745,555	1,376,267	815,132	774,235	966,597	1,397,383	3,150,448	4,989,285	4,691,057	35,199,281
2024	5,267,939	4,581,353	4,027,049	2,646,802	1,346,311	783,389	740,840	941,841	1,368,813	3,032,206	4,783,870	4,574,120	34,094,533
2023	5,109,125	4,456,931	3,910,397	2,552,327	1,317,540	753,195	709,182	918,965	1,343,082	2,922,297	4,590,699	4,461,868	33,045,607
2022	4,957,393	4,337,517	3,798,651	2,462,076	1,290,000	724,532	679,215	897,942	1,320,132	2,820,245	4,409,109	4,354,244	32,051,054
2021	4,812,701	4,223,170	3,691,849	2,376,023	1,263,755	697,394	650,905	878,757	1,299,921	2,725,634	4,238,517	4,251,230	31,109,856
											Weather Normalized Growth Rate - 3%		

13. Appendix D – Key Terms

Balancing Gas:	The volume of gas purchased for the purpose of clearing the Cumulative or Daily Operating Imbalance.
Baseload Gas:	The minimum amount of natural gas delivered or contracted over a given period of time at a steady rate or price structure.
Cap and Trade:	Ontario's cap and trade program is a market-based system that sets a hard cap on greenhouse gas emission. The cap is lowered over time and participants in the program must procure compliance instruments (e.g. emissions allowances, offset credits) to cover their annual emissions.
Clean Fuel Standard:	A performance-based approach to reducing the carbon intensity of fossil fuels that would incent the use of a broad range of low carbon fuels, energy sources and technologies, such as electricity, hydrogen, and renewable fuels, including renewable natural gas. It would establish lifecycle carbon intensity requirements separately for liquid, gaseous and solid fuels, and would go beyond transportation fuels to include those used in industry and buildings.
Contract Customers:	The maximum volume or quantity of gas that ENGLP is obligated to deliver in any one day to a customer under all services or, if the context so requires, a particular service at the consumption point.
Contract Demand ("CD"):	Means the maximum volume or quantity of Gas that Union is obligated to deliver in any one Day to ENGLP under all Services or, if the context so requires, a particular Service at the Consumption Point
Contract Year:	Means a period of twelve consecutive Months beginning on the Day of First Delivery and each anniversary date thereafter unless mutually agreed otherwise.
Dawn:	Located southeast of Sarnia, Ontario, Dawn is referred to as a Hub as it represents the point where Enbridge supply, storage and transmission systems meet. A number of other pipeline systems (e.g. TCPL, Vector) are interconnected to Enbridge Gas' distribution system at Dawn.

Federal Carbon Pricing Program A Federal carbon pricing system implemented in Ontario, under the federal Greenhouse Gas Pollution Pricing Act.

Gas Day: A period of 24 consecutive hours, beginning at 10:00 am ET. The reference date for any day shall be the calendar date upon which the twenty-four (24) hour period commences.

Gas Year: A period of twelve (12) consecutive months usually beginning on November 1st and continuing until October 31st of the following year.

Heating Degree Day: The number of degrees that a day's average temperature is below 18°C, which is the temperature below which buildings need to be heated.

Production A&B Local gas production wells located within the ENGLP franchise area. These wells are owned by Lagasco and were formerly owned by NRG. The wells were sold at the time EPCOR Utilities Inc. purchased NRG distribution system on November 1, 2017and are currently under contract to ENGLP until September 30, 2020.

Production C Local gas production wells located offshore in Lake Erie. ENGLP entered into a 5 year term contract effective October 3, 2019 in order to purchase firm gas deliveries from these wells

Rate 1– General Service Rate: Includes residential, commercial and industrial customers that constitute majority of the customer base in the ENGLP natural gas system

Rate 2– Seasonal Service: Includes mainly tobacco farming and curing customers (non-interruptible) that consume gas during the months of August and September. These customers are charged a different Delivery Charge for gas consumed between the months of April 1 through October 31 and November 1 through March 31.

Rate 3 – Special Large Volume Contract Rate:

Includes customers who enter into a contract for the purchase or transportation of gas:

- for a minimum term of one year;
- that specifies a combined daily contracted demand for firm and interruptible service of at least 700 m^3;
- a qualifying annual volume of at least 113,000 m^3.

Rate 4 – General Service Peaking:

Include primarily industrial customers whose operations can readily accept interruption and restoration of gas service within 24 hours' notice. These customers are charged a different Delivery Charge for gas consumed between the month of April 1 through December 31 and January 1 through March 31.

Rate 5 – Interruptible Peaking Contract Rate:

Includes customers who enter into a contract for the purchase or transportation of gas:

- for a minimum term of one year;
- that specifies a daily contracted demand for interruptible service of at least 700 m3
- a qualifying annual volume of at least 50,000 m3.

Rate 6 - Integrated Grain Processors Co- Operative Aylmer Ethanol Production Facility:

Rate specific to the IGPC ethanol production facility located in the Town of Aylmer.

WACOG:

Weighted Average Cost of Gas.

Western Canadian Sedimentary Basin (WCSB):

The Western Canadian Sedimentary Basin (WCSB) is a vast sedimentary basin underlying 1,400,000 square kilometres (540,000 sq mi) of Western Canada including south-western Manitoba, southern Saskatchewan, Alberta, north-eastern British Columbia and the southwest corner of the Northwest Territories. It consists of a massive wedge of sedimentary rock extending from the Rocky Mountains in the west to the Canadian Shield in the east. This wedge is about 6 kilometres (3.7 mi) thick under the Rocky Mountains, but thins to zero at its eastern margins.

14. Appendix E - Elenchus Weather Normalized Distribution System Throughput Forecast: 2021-2025

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Weather Normalized Distribution System Throughput Forecast: 2021-2025

Report prepared by
Elenchus Research Associates Inc.

Prepared for:
EPCOR Natural Gas LP

23 April 2021

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1 INTRODUCTION

This report outlines the results of, and methodology used to derive, the 2021 to 2025 weather normal throughput forecast (or "load forecast") prepared for EPCOR Natural Gas Limited Partnership ("ENGLP").

The methodology outlined in this report is virtually unchanged from the methodology used in ENGLP's 2020-24 load forecast update dated April 17, 2020. The methodology is largely consistent with the methodology used in ENGLP's 2020 COS application (EB-2018-0336) and the methodology used by Natural Gas Resources Limited ("NRG") in previous rates applications. Parties agreed to the results of the 2020 throughput forecast in settlement and the overall methodology was last approved in EB-2010-0018. Alternate methods were tested but generally found to be inferior to the previously approved methodology.

In the EB-2018-0336 settlement, ENGLP agreed to collect additional customer data to improve the quality of the forecast for its next COS application.[1] This forecast has been produced without the additional data.

> *The Parties agree ENGLP will request furnace efficiency and number of persons in household in future customer engagement surveys and will update its volume throughput and revenue forecasting methodology in its next rebasing application to reflect these variables.*

The regression equations used to normalize and forecast ENGLP's weather sensitive load use monthly heating degree days as measured at Environment Canada's London CS weather station to take into account temperature sensitivity. This location is the closest weather station to ENGLP's service territory with strong historical weather data. ENGLP experiences peak loads in winter months, though certain rate classes are not weather sensitive. Environment Canada defines heating degree days as the difference between the average daily temperature and 18°C for each day. Heating degree days is 0 when the average temperature is above 18°C. New to this forecast, Elenchus considered heating degree day data with alternate temperature thresholds other than 18°C, consistent with recent changes to electricity load forecast methodologies that have been approved by the Board.

ENGLP serves six rate classes, R1 to R6, one of which (R1) contains three sub-classes: Residential, Commercial, and Industrial. Each R1 sub-class and the R3 class are weather-sensitive. Consumption of the R2, R4, R5, and R6 rate classes are not correlated to heating degree days. Consumption per customer forecasts for the R1 sub-classes use

[1] EB-2018-0336 - Decision and Interim Rate Order, July 4, 2019 , Page 10

a baseload and excess consumption methodology to examine the impact of temperature on consumption. The R3 class' baseload consumption has fluctuated in historic years so the regression for this uses total consumption with a time trend.

The 2020 COS forecast used the 5-year rolling average consumption per customer to forecast consumption of the non-weather sensitive classes, consistent with previously approved forecasts. The 2020-24 forecast included revisions to the number of years included in the average calculations and introduced a trend to the R4 class. The 2021-25 forecast excludes 2020 from the R2 Seasonal class to account for uncharacteristically low consumption in that year, likely as the result of the COVID-19 pandemic. Consumption forecasts for non-weather sensitive classes is further described in Section 6 of this report.

In addition to the weather, economic variables, a time trend variable, number of days and number of working days in each month, number of customers, and month of year variables, have been examined for weather sensitive rate classes. A COVID variable and COVID/weather interaction variables were considered for weather-sensitive classes but found not to be statistically significant. More details on the individual class specifications are provided in the next section.

ENGLP does not have a DSM plan so no adjustments were made to the class forecasts to account for DSM savings.

1.1 SUMMARIZED RESULTS

The following table summarizes the historic and weather normalized consumption.

Normal Forecast

	2018 Actual	2019 Actual	2020 Actual	*2020 Normal*	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast
R1 Residential	17,442,260	18,000,452	16,843,918	17,620,844	18,000,822	18,601,223	19,221,294	19,861,668	20,522,997
R1 Industrial	2,050,371	2,461,420	2,103,134	2,241,827	2,248,154	2,364,079	2,485,405	2,612,369	2,745,218
R1 Commercial	5,363,288	5,890,482	5,008,664	5,344,470	5,616,718	5,789,736	5,967,885	6,151,312	6,340,168
R2 Seasonal	1,520,647	1,279,499	785,475	785,475	1,305,829	1,261,308	1,218,305	1,176,768	1,136,647
R3	1,711,013	1,510,164	1,372,226	1,390,907	1,452,982	1,388,606	1,331,446	1,280,263	1,234,092
R4	1,327,953	1,953,378	1,556,748	1,556,748	1,792,148	1,952,899	2,128,069	2,318,951	2,526,955
R5	624,337	927,203	554,438	554,438	693,203	693,203	693,203	693,203	693,203
R6	40,205,243	62,525,354	59,599,950	-	59,599,950	59,599,950	59,599,950	59,599,950	59,599,950
Total	**70,245,110**	**94,547,953**	**87,824,554**	**29,494,710**	**90,709,805**	**91,651,004**	**92,645,557**	**93,694,483**	**94,799,231**

Table 1 Consumption Forecast by class

The following table summarizes the historic and forecast customer/connections for 2018-2025:

Customers / Connections

	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast
R1 Residential	8400	8657	8839	8839	9102	9415	9769	10133
R1 Industrial	68	73	75	75	77	80	83	86
R1 Commercial	487	536	535	535	548	562	576	591
R2 Seasonal	54	49	48	49	48	46	44	43
R3	6	6	6	6	6	6	6	6
R4	37	37	40	40	42	44	45	47
R5	4	4	4	4	4	4	4	4
R6	1	1	1	1	1	1	1	1
Total	9,056	9,363	9,548	9,549	9,828	10,158	10,528	10,911

Table 2 Customer Forecast for 2013-2020

Forecasts of 2021 consumption by tier, for the classes billed based on volume tiers, is provided below.

2021 Tier Forecast

kW	Period	Tier 1	Tier 2	Tier 3	Total
R1 Residential		17,889,090	111,732		18,000,822
R1 Industrial		528,142	1,720,012		2,248,154
R1 Commercial		2,656,422	2,960,295		5,616,718
Seasonal	Apr-Oct	86,944	726,232	138,740	951,917
Seasonal	Nov-Mar	67,473	268,681	17,759	353,913
R4	Jan-Mar	28,080	5,685		33,765
R4	Apr-Dec	147,087	1,611,296		1,758,383

Table 3 2021 Consumption Forecast by Tier

2 METHODOLOGY

Energy use for R1 Residential, R1 Industrial, R1 Commercial and R3 rate classes are forecast with multivariate regressions. Regressions were not selected for R2 Seasonal, R4, R5 and R6 rate classes as these classes do not exhibit sufficient sensitivity to the explanatory variables available for a statistical regression approach.

2.1 CONSUMPTION OF WEATHER SENSITIVE CLASSES

Consumption of the three R1 rate classes are forecast using a base load and excess consumption method. Average monthly consumption per customer is first calculated for each class. The amounts are then reduced by the base load consumption, which is considered the average consumption in the summer months of July and August. The remaining consumption is considered the weather-sensitive load (or "excess" load). A baseline trend is applied to certain classes that have ongoing increasing consumption per customer that is not related to heating.

The excess load is regressed by the actual heating degree days in each month to determine the impact of cold weather on average consumption. A time-series (Prais-Winsten) regression is used to determine the coefficient, consistent with the methodology used in prior NRG throughput forecasts. A simple Ordinary Least Squares ("OLS") model is not appropriate as the errors exhibit a high level of autocorrelation (as demonstrated by Durbin-Watson statistics close to, or below, 1).

Alternate heating degree days data were also considered for each weather-sensitive class. Elenchus considered heating degree day figures for a range of reference temperatures from 10°C to 20°C. Using alternate HDD temperatures considers the possibility that classes, on average, begin consuming natural gas for their heating load at temperatures other than 18°C.

Actual heating degree days are then multiplied by the coefficients and base load consumption is added back to determine the average predicted consumption in each month. Predicted total consumption of a class is determined by multiplying this sum by the actual number of customers.

The methodology is similar for the R3 class but the base load is not removed before the regression. While the calculated base load consumption is generally consistent from year to year for the R1 classes, the base load appears to have declined in historic years. As a consequence of higher base load consumption in earlier years, the calculated base load is higher than consumption in 25 of the 107 sample months and over double the volume of consumption in the most recent summer months.

To forecast 2021-2025 consumption, forecast heating degree days figures, as described in section 4, are used in place of actual heating degree days. Weather normalized consumption in historic years is determined by removing the deviations from average weather from consumption. This is done by multiplying the coefficients by the difference between actual and average heating degree days and applying the difference to actual consumption.

A set of interaction COVID/Weather variables were considered for the weather-sensitive classes but found to be not statistically significant. The values for this variable were set to 0 in all months before March 2020 and set equal to the applicable heating degree day variable for the months of March 2020 to December 2020. This variable was intended to capture potential incremental heating load for the Residential class, and reduced heating load for non-residential classes, resulting from people staying and working from home. This indicates that COVID did not have a material impact on heating load. A COVID variable, equal to 1 from March 2020 to December 2020 and 0 in all other months, was also tested and found not to be statistically significant.

2.2 CONSUMPTION OF NON-WEATHER SENSITIVE CLASSES

Consumption of four rate classes (R2 Seasonal, R4, R5 and R6) are not weather-sensitive and do not exhibit sensitivity to the explanatory variables. Total and monthly volumes fluctuate from year to year so a rolling average is used to forecast monthly consumption for these classes, with the exception of R4 in which a trend is also applied. The number of years used in the average calculations is explained in Section 6.

2.3 CUSTOMER COUNTS

Annual customer counts for 2021-2025 are forecast by applying the geometric mean annual growth rate from 2009 to 2020 to the 2020 average customer count. Calculations for each class are provided in section 5 and 6 of this report. Monthly customer counts are derived by applying equal percentage increases in each month such that the annual average of monthly forecasts is equal to the annual forecast.

2.4 CONSUMPTION TIERS

The R1 classes, R2 Seasonal Class, and R4 classes are billed according to consumption tiers (also known as volume blocks). Historic tiered data from January 2017 to November 2018 was used to derive weather-normal tiered forecasts. The allocation from total class throughput to tiered throughput has not been updated for this forecast.

The R1 classes are billed different rates on consumption above and below a 1,000 m^3 threshold. As these classes are weather-sensitive, the share of energy consumed in each tier is determined by adjusting actual consumption in each month for each individual customer to weather normal consumption. This method allows a class' forecast consumption to be consistent with the weather normalized total volume while maintaining the consumption profile of the rate classes. The weather-normalized consumption split between Tier 1 and Tier 2 in historic years is determined for each month and used to forecast the monthly splits in the forecast months. When two years of data was available, an average of the 2017 and 2018 splits was used.

The R2 Seasonal and R4 classes are not weather-sensitive so the average of 2017 and 2018 tier splits were applied to total annual consumption. The month of December 2017 was used with the 2018 data to provide a full year of data.

3 CLASS SPECIFIC CONSUMPTION REGRESSIONS

3.1 R1 RESIDENTIAL

For the R1 Residential Class consumption the equation was estimated using 132 observations from 2010:01 to 2020:12. The natural logarithm of heating degree days at 18°C for the months of September to June were used, as measured at the London CS weather station as described in the introduction.

Several other variables were examined and found to not show a statistically significant relationship to energy usage. Those included alternate reference temperatures, economic indicators of full-time employment and GDP, days in each month, workdays in each month, a time trend, a COVID binary variable, and COVID/weather interaction variables.

A baseload trend was used to remove from 31.60m^3 in 2010 to 37.93m^3 in 2020 from the average consumption variable in each month. This amount is added back to the predicted values.

The following table outlines the resulting regression model:

Model 1: Prais-Winsten, using observations 2010:01-2020:12 (T = 132)
Dependent variable: ExLNResAverageTrend
rho = 0.2749

	coefficient	std. error	t-ratio	p-value
const	0.19922887	0.056143546	3.548562304	5.52E-04
LNHDDJanuary18	0.840990976	0.013690217	61.43006729	4.48E-93
LNHDDFebruary18	0.837655012	0.013953299	60.03275807	6.65E-92
LNHDDMarch18	0.834064746	0.014325872	58.22087002	2.40E-90
LNHDDApril18	0.803493663	0.015360764	52.30818325	6.22E-85
LNHDDMay18	0.778786064	0.017919264	43.46082922	1.10E-75
LNHDDJune18	0.546954319	0.023768939	23.0113056	5.13E-46
LNHDDSeptember18	0.459344639	0.018802194	24.43037501	1.31E-48
LNHDDOctober18	0.736756705	0.015940498	46.21917856	9.75E-79
LNHDDNovember18	0.806688474	0.014759011	54.65735278	3.78E-87
LNHDDDecember18	0.836447943	0.014070014	59.44897681	2.09E-91

Statistics based on the rho-differenced data

Mean dependent var	3.753575134	S.D. dependent var	2.02E+00
Sum squared resid	6.145678258	S.E. of regression	0.225367987
R-squared	0.988499293	Adjusted R-squared	0.987548822
F(10, 121)	662.028165	P-value(F)	1.43E-100
rho	-0.02384486	Durbin-Watson	2.05E+00

Table 4 R1 Residential Regression Model

In the above table, and all regression results tables in the section, LN denotes natural logarithm, HDD denotes heating degree days, the month name denotes a dummy variable representing 1 in the labeled month and 0 in all other months, and the '18' denotes the reference HDD temperature of 18°C. The values within the LNHDDJanuary variable, for example, includes the natural logarithm of the number of heating degree days for each January, and 0 in all other months. The label for the dependent variable includes "Ex" denoting the values of this variable are the excess consumption above the class' base load.

Using the above model coefficients, we derive the following:

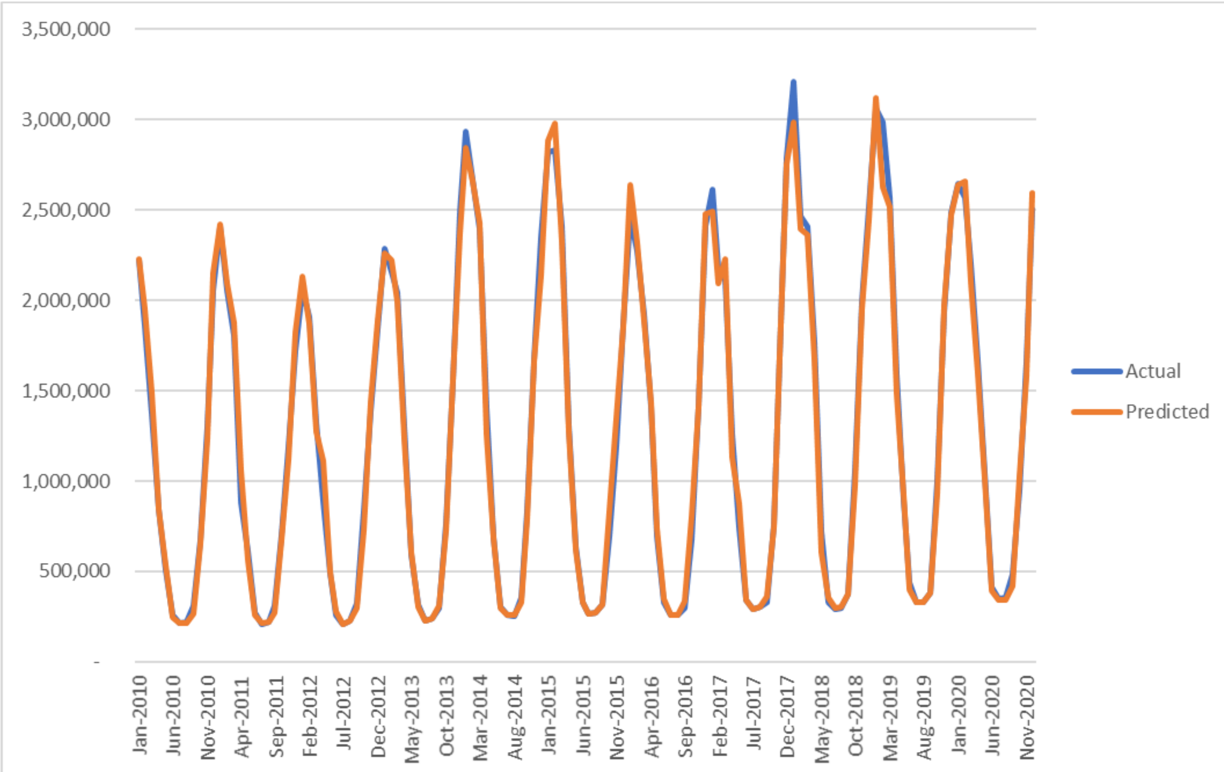

Figure 1 R1 Residential Predicted vs Actual observations

Annual estimates using actual weather are compared to actual values in the table below. Mean absolute percentage error (MAPE) for annual estimates per customer for the period is 2.3%. The MAPE calculated monthly over the period is 4.5%.

Year	Residential Actual	Predicted	Absolute Error (%)
2010	11,839,669	12,025,814	1.6%
2011	12,393,486	12,601,085	1.7%
2012	11,751,822	11,950,991	1.7%
2013	14,287,143	14,062,011	1.6%
2014	16,127,158	15,615,885	3.2%
2015	14,948,329	15,296,912	2.3%
2016	14,417,053	14,916,878	3.5%
2017	15,400,135	15,325,197	0.5%
2018	17,442,260	16,720,581	4.1%
2019	18,000,452	17,479,286	2.9%
2020	16,843,918	16,716,666	0.8%
Total	163,451,425.8	162,711,305.7	0.5%
Mean Absolute Percentage Error (Annual)			2.3%
Mean Absolute Percentage Error (Monthly)			4.5%

Table 5 R1 Residential model error

3.2 R1 INDUSTRIAL

For the R1 Industrial Class consumption the equation was estimated using 132 observations from 2010:01 to 2020:12. The natural logarithm of heating degree days at 16°C for the months from August to June were used, as measured at the London CS weather station.

Several other variables were examined and found to not show a statistically significant relationship to energy usage. Those included alternate reference temperatures, economic indicators of full-time employment and GDP, days in each month, workdays in each month, and a time trend.

A baseload trend was used to remove from 367.54m^3 in 2010 to 760.54m^3 in 2020 from the average consumption variable in each month. This amount is added back to the predicted values.

The following table outlines the resulting regression model:

Model 3: Prais-Winsten, using observations 2010:01-2020:12 (T = 132)
Dependent variable: ExLNR1AverageTrend
rho = -0.0137723

	coefficient	std. error	t-ratio	p-value
const	1.173234022	0.228772984	5.12837661	1.14E-06
LNHDDJanuary16	1.022468445	0.058467895	17.48769029	8.50E-35
LNHDDFebruary16	1.015172491	0.059532013	17.05254755	7.39E-34
LNHDDMarch16	1.033698786	0.061541865	16.79667634	2.67E-33
LNHDDApril16	1.064894715	0.067366876	15.80739354	4.10E-31
LNHDDMay16	1.102886617	0.084442702	13.06076885	8.50E-25
LNHDDJune16	0.478273565	0.158166538	3.02386061	3.05E-03
LNHDDAugust16	2.912826869	4.39E-01	6.631098768	1.01E-09
LNHDDSeptember16	1.38909527	0.107108793	12.96901244	1.40E-24
LNHDDOctober16	1.327262487	0.072749792	18.24421006	2.09E-36
LNHDDNovember16	1.226422252	0.064138972	19.12132702	3.12E-38
LNHDDDecember16	1.073294673	0.060411096	17.76651535	2.15E-35

Statistics based on the rho-differenced data

Mean dependent var	6.048425353	S.D. dependent var	2.721554733
Sum squared resid	120.6036066	S.E. of regression	1.00E+00
R-squared	0.875704664	Adjusted R-squared	8.64E-01
F(11, 120)	78.43723106	P-value(F)	2.10E-49
rho	0.000299107	Durbin-Watson	1.998672688

Table 6 R1 Industrial Regression Model

Using the above model coefficients we derive the following:

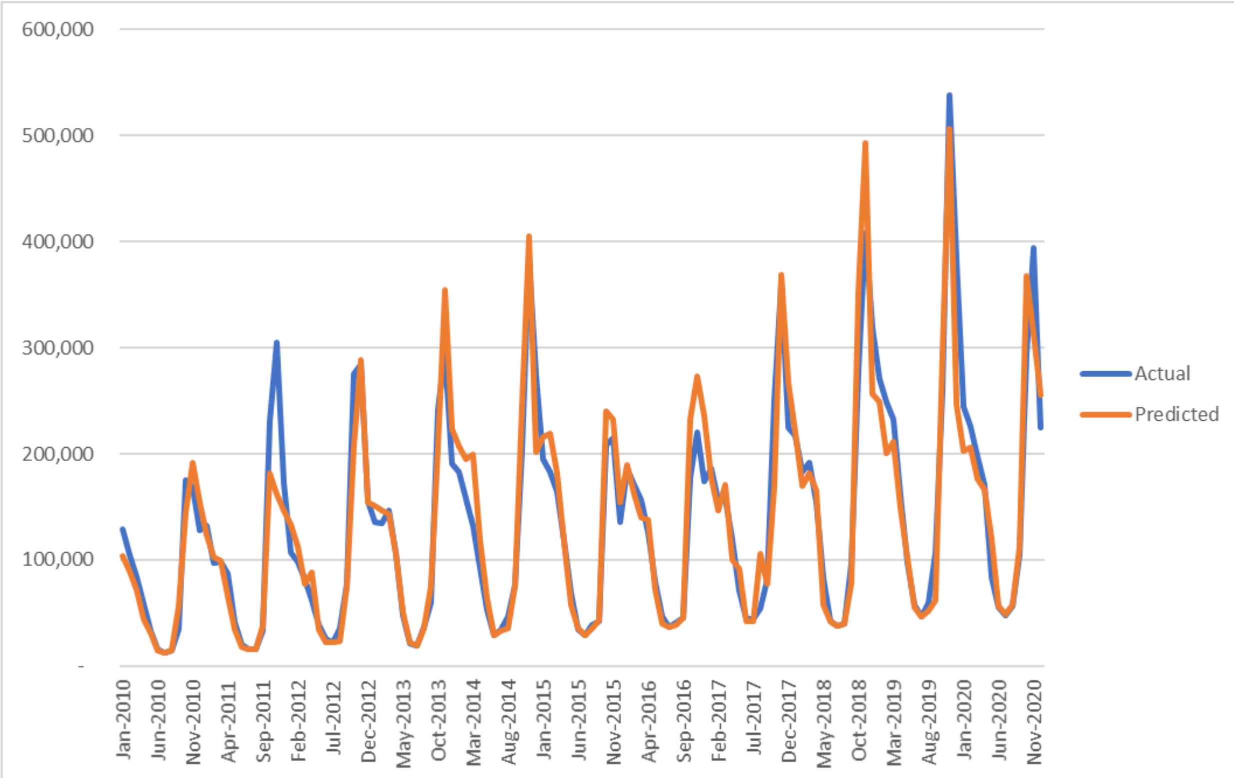

Figure 2 R1 Industrial Predicted vs Actual observations

Annual estimates using actual weather are compared to actual values in the table below. Mean absolute percentage error (MAPE) for annual estimates for the period is 7.4%. The MAPE calculated monthly over the period is 14.0%.

	R1 Industrial		Absolute
Year	Actual	Predicted	Error (%)
2010	960,283.0	930,288.4	3.1%
2011	1,247,376.0	1,003,786.2	19.5%
2012	1,265,913.0	1,239,721.6	2.1%
2013	1,436,592.0	1,536,220.5	6.9%
2014	1,666,209.0	1,811,525.1	8.7%
2015	1,430,900.0	1,562,375.1	9.2%
2016	1,462,707.0	1,605,837.1	9.8%
2017	1,752,123.4	1,759,208.0	0.4%
2018	2,050,371.1	2,096,333.5	2.2%
2019	2,461,420.1	2,173,984.3	11.7%
2020	2,103,133.8	2,082,596.7	1.0%
Total	17,837,028.3	17,801,876.4	0.2%
Mean Absolute Percentage Error (Annual)			7.4%
Mean Absolute Percentage Error (Monthly)			14.0%

Table 7 R1 Industrial model error

3.3 R1 COMMERCIAL

For the R1 Commercial Class consumption the equation was estimated using 132 observations from 2010:01 to 2020:12. The natural logarithm of heating degree days at 18°C for the months from September to June were used, as measured at the London CS weather station.

Several other variables were examined and found to not show a statistically significant relationship to energy usage. Those included alternate reference temperatures, economic indicators of full-time employment and GDP, days in each month, workdays in each month, and a time trend.

A baseload trend was used to remove from 178.39m^3 in 2010 to 227.76m^3 in 2020 from the average consumption variable in each month. This amount is added back to the predicted values.

The following table outlines the resulting regression model:

Model 4: Prais-Winsten, using observations 2010:01-2020:12 (T = 132)
Dependent variable: ExLNComAverageTrend
rho = 0.0779991

	coefficient	std. error	t-ratio	p-value
const	1.335920617	0.166980175	8.000474416	8.46E-13
LNHDDJanuary18	0.915445589	0.043053097	21.26317612	1.11E-42
LNHDDFebruary18	0.91411972	0.043815058	20.86314062	6.77E-42
LNHDDMarch18	0.906756795	0.045053947	20.1260235	2.00E-40
LNHDDApril18	0.877873548	0.048606819	18.06070768	3.81E-36
LNHDDMay18	0.845081648	0.057892689	14.59738115	1.86E-28
LNHDDJune18	0.585940865	0.082562301	7.096954127	9.41E-11
LNHDDSeptember18	0.621672571	0.065302685	9.519862367	2.24E-16
LNHDDOctober18	0.8068285	0.051494046	15.66838412	6.72E-31
LNHDDNovember18	0.87742199	0.046689718	18.79261714	1.09E-37
LNHDDDecember18	0.905793299	0.044320868	20.43717397	4.75E-41

Statistics based on the rho-differenced data

Mean dependent var	5.245229025	S.D. dependent var	2.274721427
Sum squared resid	69.15326506	S.E. of regression	0.755985838
R-squared	0.897983959	Adjusted R-squared	0.889552881
F(10, 121)	94.03474198	P-value(F)	3.58E-52
rho	-0.01332115	Durbin-Watson	2.03E+00

Table 8 R1 Commercial Regression Model

Using the above model coefficients we derive the following:

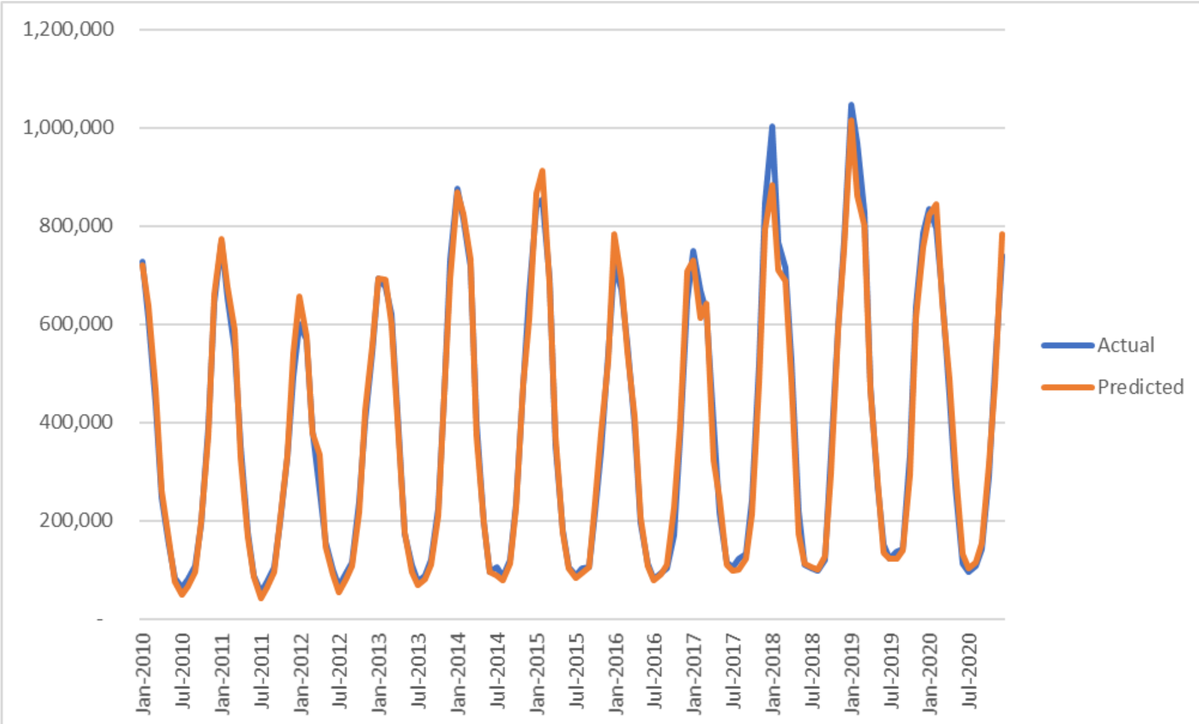

Figure 3 R1 Commercial Predicted vs Actual observations

Annual estimates using actual weather are compared to actual values in the table below. Mean absolute percentage error (MAPE) for annual estimates for the period is 3.4%. The MAPE calculated monthly over the period is 7.2%.

	R1 Commercial		Absolute
Year	Actual	Predicted	Error (%)
2010	3,735,278.0	3,766,672.4	0.8%
2011	3,846,511.0	3,892,421.3	1.2%
2012	3,526,397.0	3,620,266.7	2.7%
2013	4,352,319.0	4,239,694.1	2.6%
2014	4,788,282.0	4,691,096.4	2.0%
2015	4,420,443.0	4,531,688.8	2.5%
2016	4,117,374.0	4,353,846.5	5.7%
2017	4,734,212.7	4,466,778.7	5.6%
2018	5,363,287.7	5,025,625.4	6.3%
2019	5,890,482.0	5,602,838.8	4.9%
2020	5,008,663.8	5,187,192.0	3.6%
Total	49,783,250.2	49,378,121.2	0.8%
Mean Absolute Percentage Error (Annual)			3.2%
Mean Absolute Percentage Error (Monthly)			7.2%

Table 9 R1 Commercial model error

3.4 R3

For the R3 Class consumption the equation was estimated using 132 observations from 2010:01 to 2020:12. The natural logarithm of heating degree days at 20°C for the months from September to May were used, as measured at the London CS weather station. A natural log of a time trend is also included, beginning at ln(10) in January 2010 (increasing to ln(141) in December 2020) is used as this class exhibits declining average consumption over time.

The R3 class' customer count declined from 6 to 4 from October 2009 to June 2010, which had a clear impact on average consumption per customer, as shown on the below chart. A dummy variable is used for this period (denoted d2009), set at 1 for the months October 2009 to May 2010 and 0.5 in June 2010, the month the customer count fell to 4. A dummy variable for June was included as consumption in June was typically greater than what was expected based on the weather in that month. A dummy variable for the shoulder months of March, April, May, September, October, and November was also used to reflect lower consumption in those months than could be explained by heating degree days.

Several other variables were examined and found to not show a statistically significant relationship to energy usage. Those included alternate weather variables, economic indicators of full-time employment and GDP, days in each month, and work days in each month.

The following table outlines the resulting regression model:

Model 7: Prais-Winsten, using observations 2010:01-2020:12 (T = 132)
Dependent variable: LNContractR3Average
rho = 0.649967

	coefficient	std. error	t-ratio	p-value
const	11.69807275	0.383783398	30.48092442	8.97E-58
LNHDDJanuary20	0.255754866	0.016182462	15.80444689	6.59E-31
LNHDDFebruary20	0.24497584	0.016536079	14.81462709	1.08E-28
LNHDDMarch20	0.597939144	0.129616445	4.613142585	1.01E-05
LNHDDApril20	0.573576729	0.138241606	4.149089003	6.33E-05
LNHDDMay20	0.570181193	0.159233176	3.580793943	4.99E-04
LNHDDSeptember20	0.062388019	0.015101801	4.131164259	6.77E-05
LNHDDOctober20	0.547511593	0.145577953	3.760951317	2.65E-04
LNHDDNovember20	0.57437039	0.134174637	4.280767231	3.81E-05
LNHDDDecember20	0.235176727	0.016117707	14.59120248	3.45E-28
lnTrend	-0.573550983	0.090048056	-6.369387756	3.80E-09
d2009	-1.044910953	0.243865003	-4.284792578	3.75E-05
Shoulder	-2.300785244	0.8301463	-2.771541888	6.48E-03
June	0.209294697	0.071766575	2.92E+00	0.004240369

Statistics based on the rho-differenced data

Mean dependent var	10.17453679	S.D. dependent var	7.52E-01
Sum squared resid	5.614873186	S.E. of regression	2.18E-01
R-squared	0.924370298	Adjusted R-squared	9.16E-01
F(13, 118)	62.9287524	P-value(F)	1.06E-46
rho	0.019616694	Durbin-Watson	1.95E+00

Table 10 R3 Regression Model

Using the above model coefficients we derive the following:

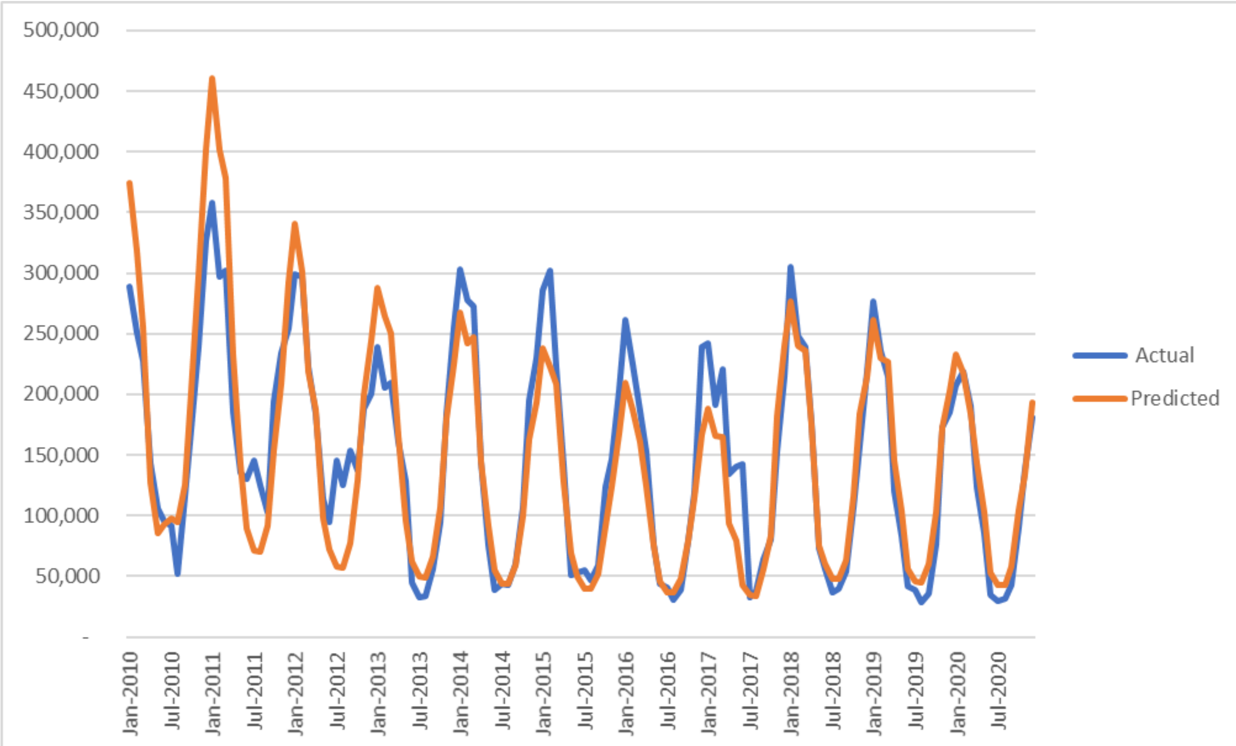

Figure 4 R3 Predicted vs Actual observations

Annual estimates using actual weather are compared to actual values in the table below. Mean absolute percentage error (MAPE) for annual estimates for the period is 10.6%. The MAPE calculated monthly over the period is 21.6%. The MAPEs are relatively high for this class but more variance can be expected in a class with only 4 to 6 customers.

Year	**R3** Actual	Predicted	Absolute Error (%)
2010	2,108,344.0	2,472,802.9	17.3%
2011	2,464,687.0	2,593,386.6	5.2%
2012	2,161,705.0	1,983,945.6	8.2%
2013	1,644,742.0	1,804,377.3	9.7%
2014	1,792,006.0	1,651,329.1	7.9%
2015	1,692,328.0	1,431,363.2	15.4%
2016	1,492,346.0	1,284,767.5	13.9%
2017	1,653,466.4	1,365,856.9	17.4%
2018	1,711,012.7	1,736,459.6	1.5%
2019	1,510,163.8	1,652,775.9	9.4%
2020	1,372,226.2	1,510,712.2	10.1%
Total	19,603,027.0	19,487,776.7	0.6%
Mean Absolute Percentage Error (Annual)			10.6%
Mean Absolute Percentage Error (Monthly)			21.6%

Table 11 R3 model error

4 WEATHER NORMALIZATION

It is not possible to accurately forecast weather for months or years in advance. Therefore, one can only base future weather expectations on what has happened in the past. Individual years may experience unusual spells of weather (unusually cold winter, unusually warm summer, etc.). However, over time, these unusual spells "average" out. While there may be trends over several years (e.g., warmer winters for example), using several years of data rather than one particular year filters out the extremes of any particular year. While there are several different approaches to determining an appropriate weather normal, ENGLP has adopted the 10-year trend of 10-year monthly degree day averages.

Various methods were analysed to determine the most appropriate methodology to forecast monthly heating degree days from 2021 to 2025. A 5-year average, 10-year average, 20-year trend, 5-year weighted average, 10-year trend of 5 year averages, 10-year trend of 10-year averages, and the midpoint of the 10-year average and 20-year trend were considered.

Data from 1981 to 2020 was used to evaluate each method's predicted heating degree days against the actual heating degree days for each month since January 2001. Data from Environment Canada's London Airport weather station was used for the period from 1981 to 2002. London Airport's temperature data is only provided until 2002, which is approximately when temperature data for London CS begins. Data from the London A weather station (another London Airport weather station with temperature data as of March 2012) is used in place of London CS when data from that station is unavailable.

Each method was ranked according to the magnitude of the deviations between predicted and actual heating degree days, with 1 being the closest predicted value and 7 being the furthest. The rankings were done on monthly and annual bases. The following table shows the annual rankings, average annual and monthly rankings, and variance of the deviations on monthly and annual bases.

Year	5-Year Average	10-Year Average	20-Year Trend	Weighted 5-Year Average	10-Year Trend (5MA)	10-Year Trend (10MA)	10-Yr Avg & 20-Yr Trend Midpoint
2001	2	5	3	1	7	6	4
2002	2	5	1	4	7	6	3
2003	7	2	5	6	4	1	3
2004	6	2	5	4	7	1	3
2005	4	3	6	2	7	1	5
2006	6	2	4	7	1	5	3
2007	2	4	6	3	7	1	5
2008	1	4	6	3	7	2	5
2009	1	2	6	3	4	7	5
2010	3	5	2	7	6	1	4
2011	1	6	5	4	7	2	3
2012	5	6	1	4	7	3	2
2013	4	3	7	6	1	2	5
2014	4	2	7	6	3	1	5
2015	4	2	5	1	7	6	3
2016	6	3	5	7	1	2	4
2017	2	4	6	7	1	3	5
2018	1	5	2	7	6	3	4
2019	1	6	4	7	2	3	5
2020	1	3	5	6	7	2	4
Average Rank							
Monthly	3.25	3.70	4.60	4.50	4.90	3.10	3.95
Annual	3.15	3.70	4.55	4.75	4.95	2.90	4.00
Variance of Difference between Predicted and Actual							
Monthly	4,017	3,624	4,092	4,373	3,943	3,587	3,817
Annual	67,048	60,028	67,003	74,420	70,291	55,585	62,536

Table 12 HDD Rankings and Variance

The rankings and variance analysis reveals that the 10-year trend of the 10-year average is the best methodology for predicting future heating degree days. On a monthly and annual basis, the predicted heating degree days using this methodology is closest to actual heating degree days and the deviations from actual weather have the lowest variance among the methods analysed.

For clarity, the 10-year trend of the 10-year moving average is the annualized trend of one 10-year period to the next 10-year period. For example, the 2001 predicted value uses the trend from the average heating degree days from 1981 and 1990 to the average from 1991 and 2000.

This method is the best predictive method as it accounts for trends in heating degree days over time without being over-reliant on data of any one year. Simple averages do not consider weather trends over time and typical trend forecasts can be significantly impacted by single data points.

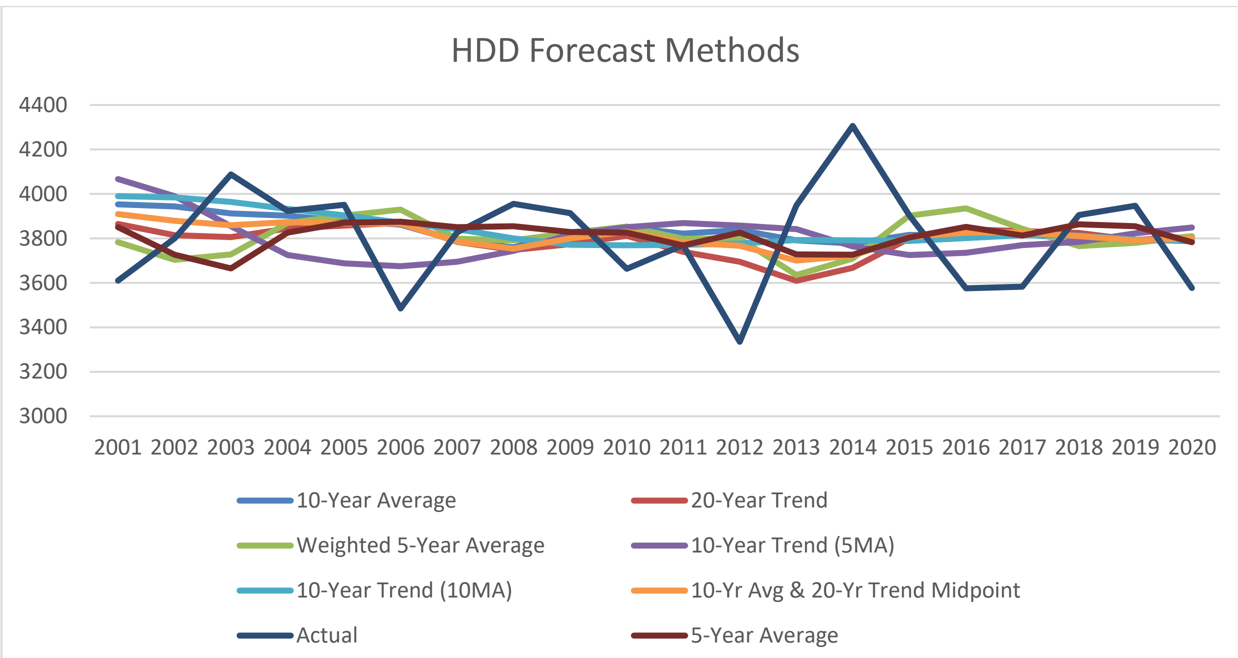

Figure 5 Weather Forecast for Various Methods

The monthly predicted and forecast heating degree days are detailed in the following tables for heating degree days at 18°C.

18°C	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	**Total**	**Actual**
2011	716	637	552	312	165	34	6	10	63	257	401	638	**3,791**	**3,769**
2012	719	648	554	309	165	33	6	10	63	258	400	638	**3,803**	**3,335**
2013	721	656	548	307	161	32	6	10	65	256	401	634	**3,798**	**3,949**
2014	720	661	543	307	156	31	6	11	68	253	406	633	**3,794**	**4,306**
2015	719	667	545	310	151	29	6	10	72	250	416	630	**3,804**	**3,904**
2016	722	677	548	313	144	28	7	10	74	249	422	618	**3,813**	**3,575**
2017	727	682	547	318	138	28	7	11	74	246	424	611	**3,813**	**3,582**
2018	727	676	547	319	133	29	7	11	74	243	424	608	**3,798**	**3,905**
2019	732	668	547	325	126	29	7	11	74	241	427	604	**3,792**	**3,947**
2020	733	662	549	332	124	29	6	10	73	239	435	601	**3,793**	**3,577**
2021	730	654	553	345	123	29	5	10	71	237	440	589	**3,787**	
2022	731	653	554	349	119	28	5	10	71	236	443	585	**3,784**	
2023	731	652	554	353	116	28	5	10	71	234	446	580	**3,781**	
2024	732	651	555	357	112	28	5	10	71	232	449	576	**3,778**	
2025	732	650	556	361	109	28	5	10	71	231	453	572	**3,776**	

Table 13 Forecast HDD 18°C

5 WEATHER-NORMALIZED CLASS FORECASTS

5.1 R1 RESIDENTIAL

Incorporating the normalized and forecast heating degree days the following weather corrected consumption and forecast values are calculated:

		R1 Residential				
		Consumption			Normalized	
Year	Customers	Per Customer	Total	Actual	Per Customer	Total
2010	6,472	1,827	11,824,006	11,839,669	1,865	12,081,050
2011	6,609	1,876	12,400,852	12,393,486	1,879	12,419,935
2012	6,896	1,705	11,756,626	11,751,822	1,894	13,047,079
2013	7,181	1,990	14,289,175	14,287,143	1,954	14,025,849
2014	7,470	2,162	16,150,603	16,127,158	1,999	14,920,856
2015	7,726	1,938	14,974,492	14,948,329	1,898	14,660,091
2016	7,956	1,813	14,425,323	14,417,053	1,886	14,997,421
2017	8,110	1,892	15,347,218	15,400,135	1,981	16,110,118
2018	8,400	2,075	17,426,321	17,442,260	2,051	17,239,167
2019	8,657	2,083	18,035,211	18,000,452	2,030	17,543,637
2020	8,839	1,905	16,834,984	16,843,918	1,992	17,620,844
2021	9,102				1,982	18,000,822
2022	9,415				1,989	18,601,223
2023	9,769				1,996	19,221,294
2024	10,133				2,002	19,861,668
2025	10,504				2,009	20,522,997

Table 14 Actual vs Normalized R1 Residential

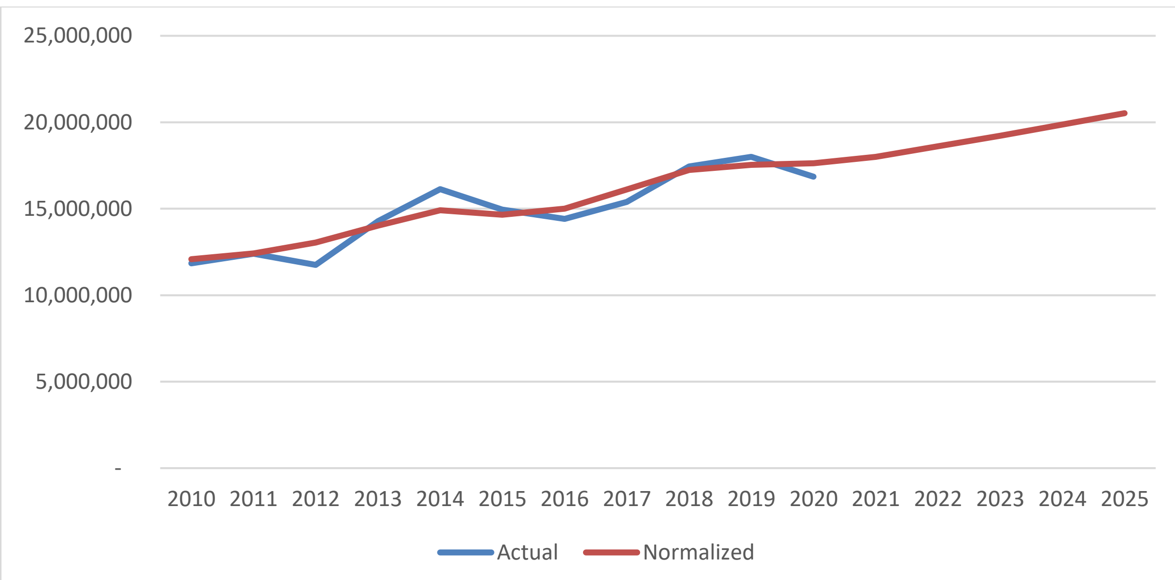

Figure 6 Actual vs Normalized R1 Residential

A tiered forecast was produced using actual individual customer data adjusted to weather-normal consumption.

R1 Residential			
	Tier 1	Tier 2	Total
2019	17,889,403	111,049	18,000,452
2020	16,742,865	101,053	16,843,918
2021	17,889,090	111,732	18,000,822
2022	18,485,959	115,264	18,601,223
2023	19,102,387	118,907	19,221,294
2024	19,739,004	122,664	19,861,668
2025	20,396,459	126,538	20,522,997

Table 15 Forecasted R1 Residential Tiered Consumption

The Geometric mean of the annual growth from 2009 to 2020 was used to forecast the growth rate from 2021 to 2025. In addition to ongoing growth in line with historic customer growth, 75 R1 Residential customers were added each year beginning in 2022 to account for a new housing development.

Year	Residential Customers	Percent of Prior Year
2009	6,396	
2010	6,472	101.2%
2011	6,609	102.1%
2012	6,896	104.3%
2013	7,181	104.1%
2014	7,470	104.0%
2015	7,726	103.4%
2016	7,956	103.0%
2017	8,110	101.9%
2018	8,400	103.6%
2019	8,657	103.1%
2020	8,839	102.1%
2021	9,102	103.0%
2022	9,415	103.4%
2023	9,769	103.8%
2024	10,133	103.7%
2025	10,504	103.7%

Table 16 Forecasted R1 Residential Customer Count

5.2 R1 INDUSTRIAL

Incorporating the normalized and forecast heating degree days the following weather corrected consumption and forecast values are calculated:

R1 Industrial

Year	Customers	Consumption Per Customer	Consumption Total	Actual	Normalized Per Customer	Normalized Total
2010	43	24,101	1,034,341	960,283	25,497	1,016,628
2011	43	28,608	1,225,376	1,247,376	30,829	1,354,179
2012	51	24,350	1,252,019	1,265,913	26,904	1,397,169
2013	58	24,752	1,429,444	1,436,592	24,048	1,395,271
2014	63	26,306	1,659,456	1,666,209	24,042	1,523,275
2015	62	23,186	1,439,435	1,430,900	24,274	1,494,170
2016	65	22,433	1,461,881	1,462,707	24,607	1,605,390
2017	66	26,620	1,752,499	1,752,123	29,299	1,928,216
2018	68	29,425	2,005,771	2,050,371	28,238	1,963,885
2019	73	33,281	2,440,611	2,461,420	33,708	2,486,345
2020	75	28,106	2,103,289	2,103,134	29,950	2,241,827
2021	77				29,072	2,248,154
2022	80				29,533	2,364,079
2023	83				29,995	2,485,405
2024	86				30,456	2,612,369
2025	89				30,918	2,745,218

Table 17 Actual vs Normalized R1 Industrial

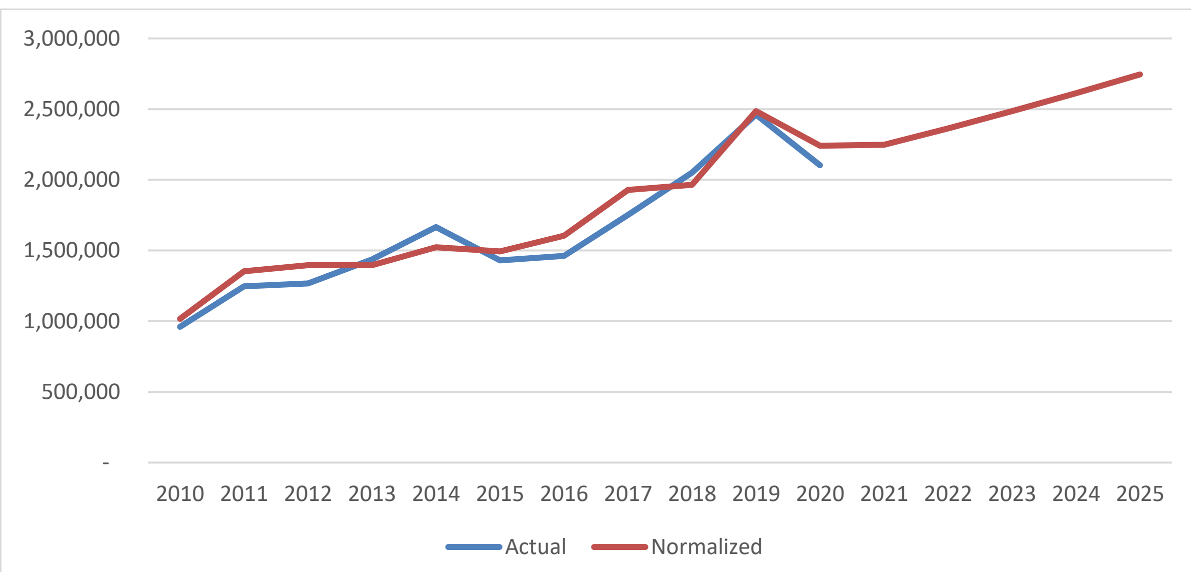

Figure 7 Actual vs Normalized R1 Industrial

A tiered forecast was produced using actual individual customer data adjusted to weather-normal consumption.

	R1 Industrial		
	Tier 1	**Tier 2**	**Total**
2019	569,966	1,891,454	2,461,420
2020	492,111	1,618,640	2,103,134
2021	528,142	1,720,012	2,248,154
2022	557,794	1,806,285	2,364,079
2023	588,884	1,896,521	2,485,405
2024	621,477	1,990,892	2,612,369
2025	655,640	2,089,578	2,745,218

Table 18 Forecasted R1 Industrial Tiered Consumption

The Geometric mean of the annual growth from 2009 to 2020 was used to forecast the growth rate from 2021 to 2025. The number of customers in this class grew significantly from 2009 to 2016 so the growth rates from these years was excluded as they do not reflect the current customer growth trend.

The following table includes the customer Actual / Forecast customer count on this basis:

R1 Industrial		
Year	Customers	Percent of Prior Year
2009	30	
2010	43	141.5%
2011	43	99.8%
2012	51	120.0%
2013	58	112.3%
2014	63	109.2%
2015	62	98.4%
2016	65	105.0%
2017	66	101.0%
2018	68	103.5%
2019	73	107.6%
2020	75	102.0%
2021	77	103.5%
2022	80	103.5%
2023	83	103.5%
2024	86	103.5%
2025	89	103.5%

Table 19 Forecasted R1 Industrial Customer Count

5.3 R1 COMMERCIAL

Incorporating the normalized and forecast heating degree days the following weather corrected consumption and forecast values are calculated:

R1 Commercial						
Year	Customers	Consumption Per Customer	Consumption Total	Actual	Normalized Per Customer	Normalized Total
2010	405	9,216	3,736,259	3,735,278	9,409	3,814,488
2011	405	9,477	3,833,380	3,846,511	9,485	3,848,853
2012	415	8,515	3,533,844	3,526,397	9,510	3,935,711
2013	424	10,227	4,336,095	4,352,319	10,016	4,261,705
2014	437	10,964	4,795,706	4,788,282	10,071	4,399,620
2015	445	9,935	4,421,983	4,420,443	9,703	4,320,400
2016	453	9,065	4,102,131	4,117,374	9,444	4,288,624
2017	462	10,219	4,716,893	4,734,213	10,746	4,974,994
2018	487	10,958	5,332,657	5,363,288	10,833	5,299,597
2019	536	10,970	5,880,685	5,890,482	10,691	5,741,278
2020	535	9,341	4,997,267	5,008,664	9,966	5,344,470
2021	548				10,265	5,616,718
2022	562				10,320	5,789,736
2023	576				10,376	5,967,885
2024	591				10,431	6,151,312
2025	606				10,487	6,340,168

Table 20 Actual vs Normalized R1 Commercial

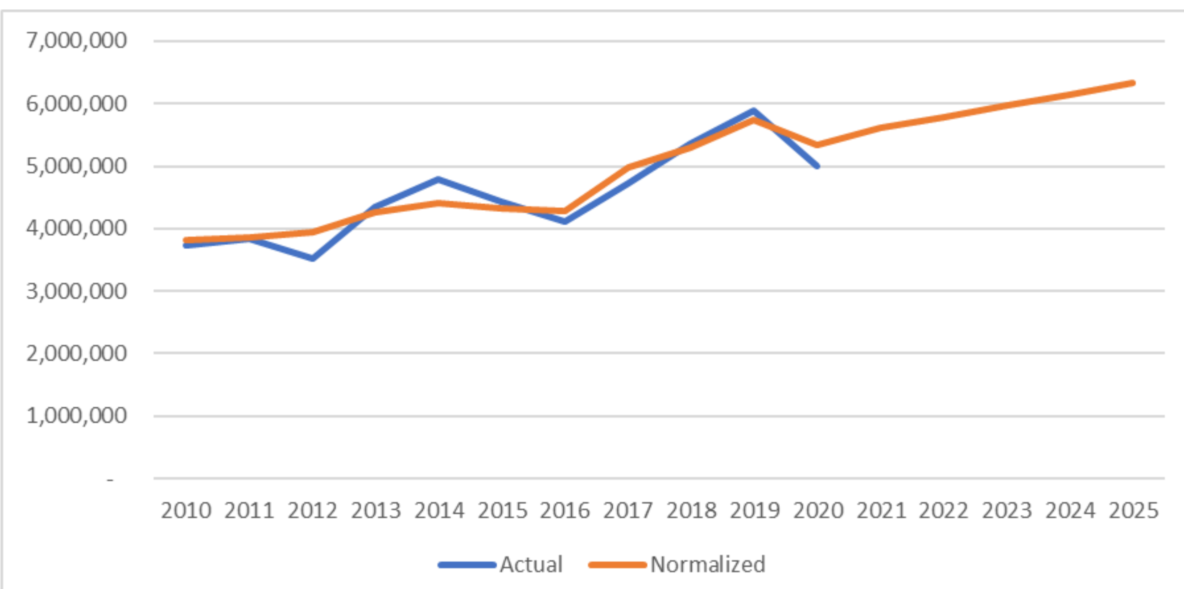

Figure 8 Actual vs Normalized R1 Commercial

A tiered forecast was produced using actual individual customer data adjusted to weather-normal consumption.

	R1 Commercial		
	Tier 1	**Tier 2**	**Total**
2019	2,783,094	3,107,388	5,890,482
2020	2,378,617	2,630,047	5,008,664
2021	2,656,422	2,960,295	5,616,718
2022	2,740,264	3,049,472	5,789,736
2023	2,826,631	3,141,254	5,967,885
2024	2,915,597	3,235,715	6,151,312
2025	3,007,237	3,332,932	6,340,168

Table 21 Forecasted R1 Commercial Tiered Consumption

The Geometric mean of the annual growth from 2009 to 2020 was used to forecast the growth rate from 2021 to 2025.

The following table includes the customer Actual / Forecast customer count on this basis:

Year	R1 Commercial Customers	Percent of Prior Year
2009	407	
2010	405	99.7%
2011	405	99.8%
2012	415	102.6%
2013	424	102.2%
2014	437	103.2%
2015	445	101.8%
2016	453	101.7%
2017	462	102.0%
2018	487	105.4%
2019	537	110.4%
2020	40	110.2%
2021	42	103.5%
2022	43	103.5%
2023	45	103.5%
2024	46	103.5%
2025	48	103.5%

Table 22 Forecasted R1 Commercial Customer Count

5.4 R3

Incorporating the normalized and forecast heating degree days, continuing time trend and calendar dummy variables, the following weather corrected consumption and forecast values are calculated:

R3						
Year	Customers	Consumption		Actual	Normalized	
		Per Customer	Total		Per Customer	Total
2010	5	445,893	2,117,993	2,108,344	455,808	2,164,105
2011	4	616,172	2,464,687	2,464,687	620,232	2,480,927
2012	4	540,426	2,161,705	2,161,705	568,461	2,273,842
2013	4	411,186	1,644,742	1,644,742	407,844	1,631,377
2014	4	448,002	1,792,006	1,792,006	427,485	1,709,940
2015	4	423,082	1,692,328	1,692,328	420,453	1,681,813
2016	4	373,087	1,492,346	1,492,346	379,935	1,519,741
2017	5	375,566	1,690,049	1,653,466	380,533	1,671,804
2018	6	285,169	1,711,013	1,711,013	280,397	1,682,381
2019	6	251,694	1,510,164	1,510,164	244,658	1,467,951
2020	6	228,704	1,372,226	1,372,226	231,818	1,390,907
2021	6				242,164	1,452,982
2022	6				231,434	1,388,606
2023	6				221,908	1,331,446
2024	6				213,377	1,280,263
2025	6				205,682	1,234,092

Table 23 Actual vs Normalized R3

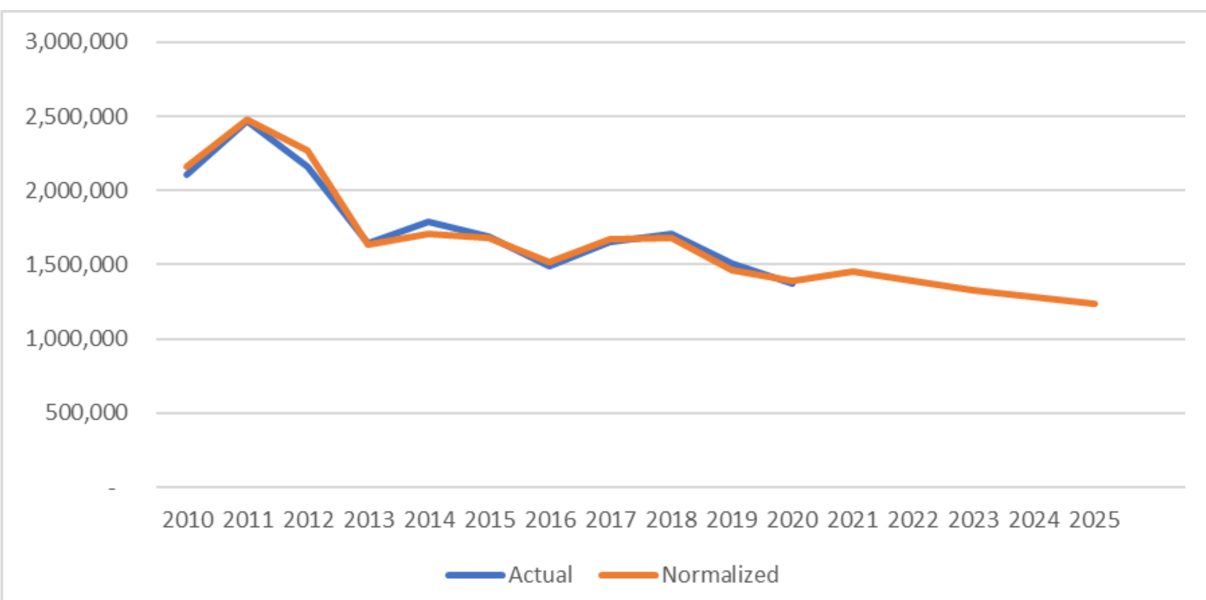

Figure 9 Actual vs Normalized R3

The R3 class has fluctuated between 4 and 6 customers since 2009. The current count of 6 customers is expected to continue through 2021-2025.

6 NON-WEATHER SENSITIVE CLASS FORECASTS

6.1 R2 SEASONAL

Monthly consumption is forecast using a three-year average of consumption per customer in each month. Consumption in 2020 was materially lower than previous years so it was excluded from the average calculation. Additionally, a large new customer is forecast to attach in 2021. An amount equal to forecast consumption incremental to average consumption is added to account for the forecasted increase in consumption per customer. The sum of monthly forecast values per customer are used to calculate annual total consumption as follows:

R2 Seasonal						
Year	Customers	Consumption Per Customer	Consumption Total	Actual	Forecast Per Customer	Forecast Total
2010	65	25,388	1,650,218	1,638,992		
2011	65	27,387	1,768,757	1,849,679		
2012	66	28,174	1,868,851	1,885,826		
2013	64	28,302	1,820,741	1,844,495		
2014	65	30,594	1,980,940	1,988,124		
2015	63	20,017	1,256,038	1,242,867		
2016	59	23,524	1,382,013	1,394,132		
2017	55	26,211	1,435,062	1,410,653		
2018	54	28,488	1,526,500	1,520,647		
2019	49	25,819	1,267,264	1,279,499		
2020	48	16,230	783,102	785,475		
2021	48				28,195	1,305,829
2022	46				28,195	1,261,308
2023	44				28,195	1,218,305
2024	43				28,195	1,176,768
2025	42				28,195	1,136,647

Table 24 Actual vs Normalized R2 Seasonal

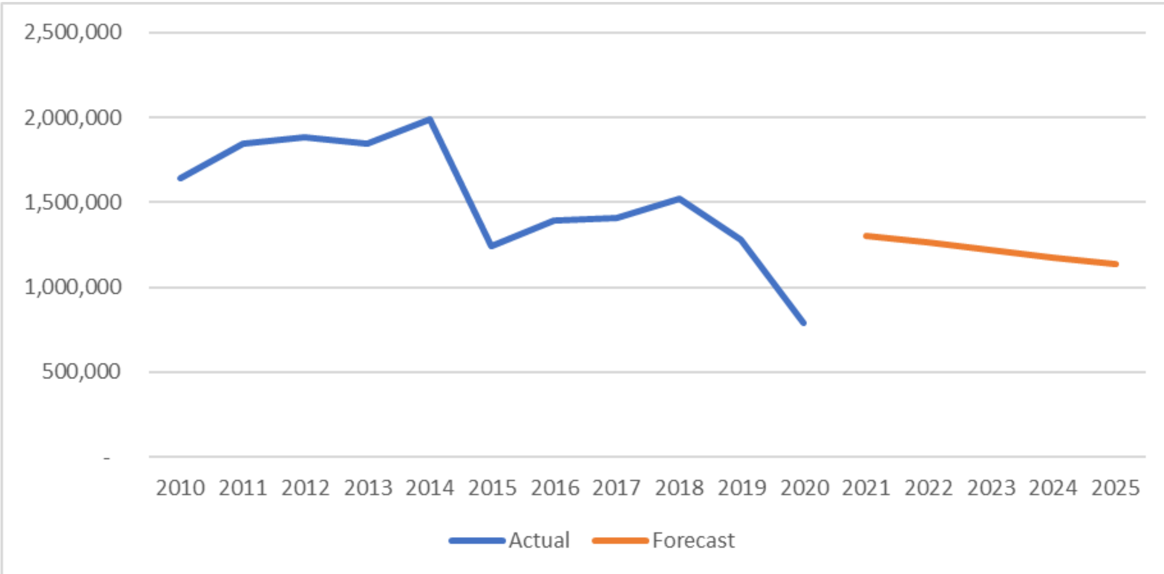

Figure 10 Actual vs Normalized R2 Seasonal

An average of tiered consumption shares in 2017 and 2018 was used to forecast tiered consumption in future years. The R2 seasonal class has three tiers with different rates in April to October and November to March. Tier 1 consumption is consumption up to 1,000 m^3, tier 2 applies to consumption between 1,000 m^3 and 25,000 m^3, and all consumption above 25,000 m^3 is considered Tier 3.

R2 Seasonal

	April 1 to Oct 31			Nov 1 to Mar 31			
	Tier 1	**Tier 2**	**Tier 3**	**Tier 1**	**Tier 2**	**Tier 3**	**Total**
2019	85,191	711,589	135,943	66,113	263,263	17,401	1,279,499
2020	52,298	436,839	83,454	40,586	161,615	10,682	785,475
2021	86,944	726,232	138,740	67,473	268,681	17,759	1,305,829
2022	83,980	701,472	134,010	65,173	259,520	17,154	1,261,308
2023	81,117	677,556	129,441	62,951	250,672	16,569	1,218,305
2024	78,351	654,455	125,028	60,804	242,126	16,004	1,176,768
2025	75,680	632,142	120,765	58,731	233,870	15,458	1,136,647

Table 25 Forecasted R2 Seasonal Tiered Consumption

The Geometric mean of the annual growth from 2009 to 2020 was used to forecast the growth rate from 2021 to 2025, plus the known additional customer in 2021.

The following table includes the customer Actual / Forecast customer count on this basis:

Year	R2 Seasonal Customers	Percent of Prior Year
2009	71	
2010	65	92.0%
2011	65	99.4%

2012	66	102.7%
2013	64	97.0%
2014	65	100.6%
2015	63	96.9%
2016	59	93.6%
2017	55	93.2%
2018	54	97.9%
2019	49	91.6%
2020	48	98.3%
2021	48	99.5%
2022	46	96.6%
2023	44	96.6%
2024	43	96.6%
2025	42	96.6%

Table 26 Forecasted R2 Seasonal Customer Count

6.2 R4

Consumption per R4 customer is not consistent and shows a clear increasing trend so the 5-year average does not accurately reflect current consumption for the class. The 2020 forecast is instead based on a 3-year average and the trend in consumption per customer is forecast to continue through to 2025. The trend, 5.277%, is derived as the geometric mean of year over year changes to the 3-year rolling average from 2013-2015 to 2018-2020. Additionally, one known large customer is forecast to attach in 2021. The incremental consumption implies a 11.29% increase in consumption in 2021, which is followed by 5.277% increases from 2022 to 2025.

R4						
Year	Customers	Consumption Per Customer	Consumption Total	Actual	Forecast Per Customer	Forecast Total
2010	23	11,597	269,634	267,879		
2011	23	21,688	487,988	477,633		
2012	25	23,036	575,898	678,458		
2013	32	26,175	831,059	861,111		
2014	33	39,661	1,318,721	1,345,169		
2015	34	29,232	996,339	994,710		
2016	35	25,140	888,266	904,160		
2017	36	31,238	1,119,348	1,124,029		
2018	37	35,029	1,278,561	1,327,953		
2019	37	50,232	1,841,844	1,953,378		
2020	40	37,680	1,522,890	1,556,748		
2021	42				41,932	1,792,148
2022	44				44,145	1,952,899
2023	45				46,474	2,128,069
2024	47				48,926	2,318,951
2025	49				51,508	2,526,955

Table 27 Actual vs Forecast R4

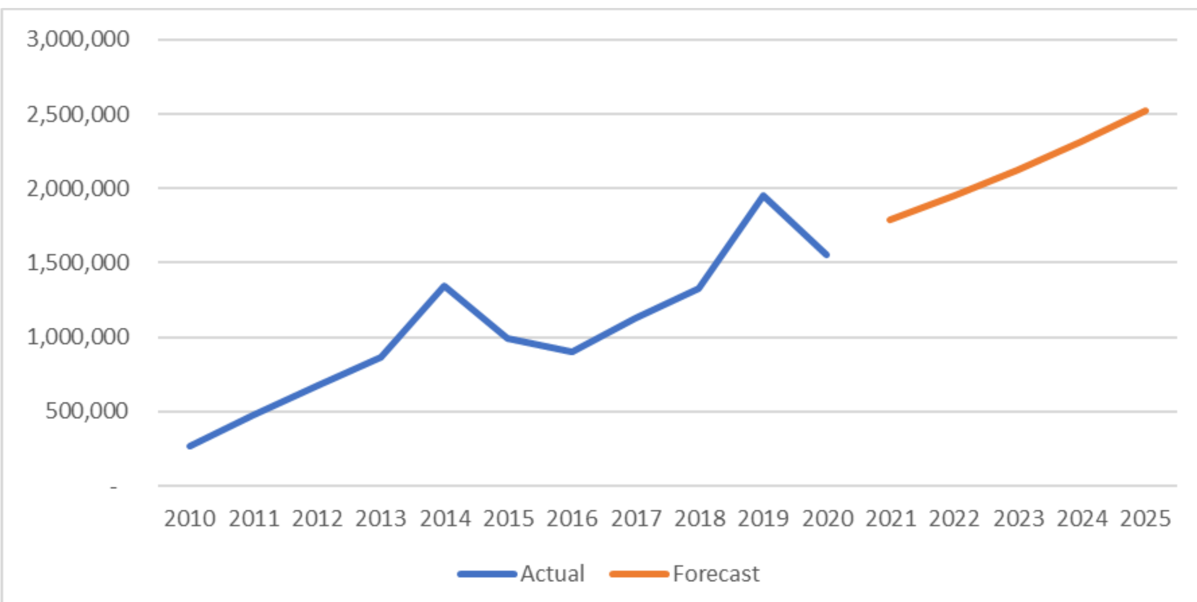

Figure 11 Actual vs Normalized R4

An average of tiered consumption shares in 2017 and 2018 was used to forecast tiered consumption in future years. The R4 class has two tiers with different rates in January to March and April to December. Tier 1 consumption is consumption up to 1,000 m^3 and all consumption above 1,000 m^3 is considered tier 2.

	R4				
	Jan 1 to Mar 31		Apr 1 to Dec 31		
	Tier 1	Tier 2	Tier 1	Tier 2	Total
2019	30,607	6,196	160,320	1,756,256	1,953,378
2020	24,392	4,938	127,767	1,399,651	1,556,748
2021	28,080	5,685	147,087	1,611,296	1,792,148
2022	30,599	6,195	160,280	1,755,825	1,952,899
2023	33,344	6,750	174,657	1,913,318	2,128,069
2024	36,335	7,356	190,323	2,084,937	2,318,951
2025	39,594	8,016	207,395	2,271,951	2,526,955

Table 28 Forecasted R4 Tiered Consumption

The Geometric mean of the annual growth from 2014 to 2020 was used to forecast the growth rate from 2021 to 2025. The number of customers in this class grew significantly from 2009 to 2013 so the growth rates from these years was excluded as they do not reflect the current customer growth trend.

The following table includes the customer Actual / Forecast customer count on this basis:

Year	R4 Customers	Percent of Prior Year
2009	23	
2010	23	101.1%
2011	23	96.8%
2012	25	111.1%
2013	32	127.0%
2014	33	104.7%
2015	34	102.5%
2016	35	103.7%
2017	36	101.4%
2018	37	101.9%
2019	37	100.5%
2020	40	110.2%
2021	40	103.5%
2022	42	103.5%
2023	44	103.5%
2024	45	103.5%
2025	47	103.5%

Table 29 Forecasted R4 Customer Count

6.3 R5

Consumption per R5 customer has fluctuated considerably since 2001. The 2021-2025 forecast is based on a 3-year average from 2018 to 2020, which is in line with average consumption per customer per year since 2010.

R5						
Year	Customers	Consumption Per Customer	Consumption Total	Actual	Forecast Per Customer	Forecast Total
2010	5	138,769	728,538	697,560		
2011	5	222,975	1,114,874	1,114,874		
2012	5	177,350	886,748	886,748		
2013	5	203,326	1,016,630	1,016,630		
2014	5	225,771	1,147,669	1,128,958		
2015	5	134,524	672,622	672,622		
2016	5	112,572	562,860	562,860		
2017	5	186,530	870,472	753,900		
2018	4	149,492	610,424	624,337		
2019	4	231,801	927,203	927,203		
2020	4	138,609	554,438	554,438	173,301	693,203
2021	4				173,301	693,203
2022	4				173,301	693,203
2023	4				173,301	693,203
2024	4				173,301	693,203
2025	4				173,301	693,203

Table 30 Actual vs Forecast R5

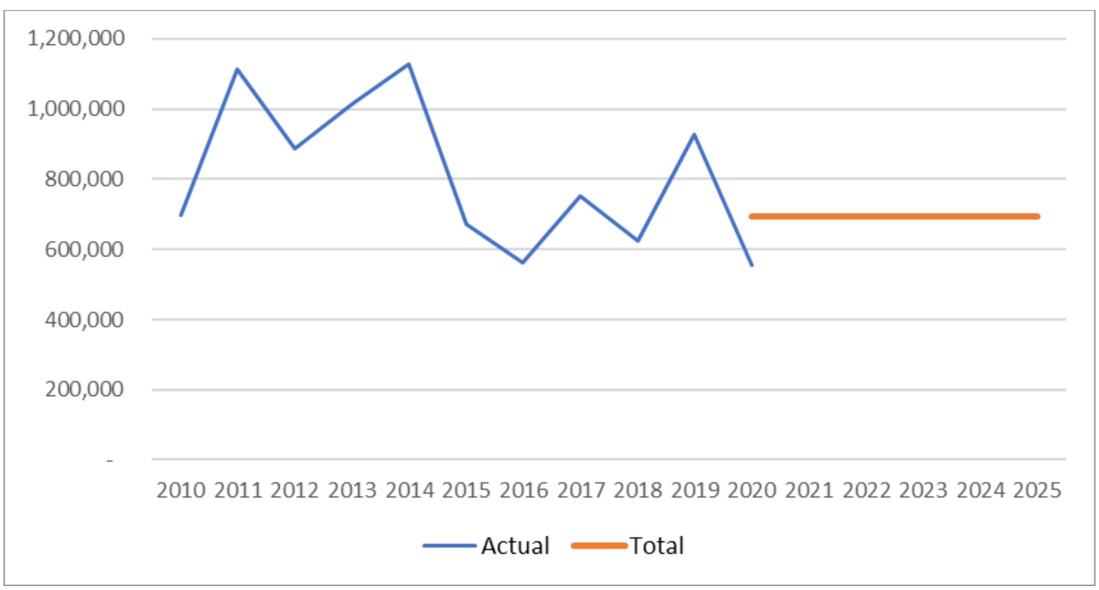

Figure 12 Actual vs Normalized Large Use R5

The R5 class had 5 customers from 2009 to 2017 and had 4 customers from 2018 to 2020. It is expected to maintain 4 customers through 2021 to 2025.

6.4 R6

R6 consumption increases significantly in 2019 and 2020 over historic volumes. The 2021-2025 forecast uses 2010 consumption as forecast consumption in each year.

R6						
Year	Customers	Consumption		Actual	Forecast	
		Per Customer	Total		Per Customer	Total
2010	1	33,459,684	33,459,684	33,459,684		
2011	1	30,758,504	30,758,504	30,758,504		
2012	1	31,628,262	31,628,262	31,628,262		
2013	1	31,582,423	31,582,423	31,582,423		
2014	1	31,735,774	31,735,774	31,735,774		
2015	1	34,710,609	34,710,609	34,710,609		
2016	1	40,074,176	40,074,176	40,074,176		
2017	1	36,485,139	36,485,139	36,485,139		
2018	1	40,205,243	40,205,243	40,205,243		
2019	1	62,525,354	62,525,354	62,525,354		
2020	1	59,599,950	59,599,950	59,599,950	59,599,950	59,599,950
2021	1				59,599,950	59,599,950
2022	1				59,599,950	59,599,950
2023	1				59,599,950	59,599,950
2024	1				59,599,950	59,599,950
2025	1				59,599,950	59,599,950

Table 31 Actual vs Forecast R6

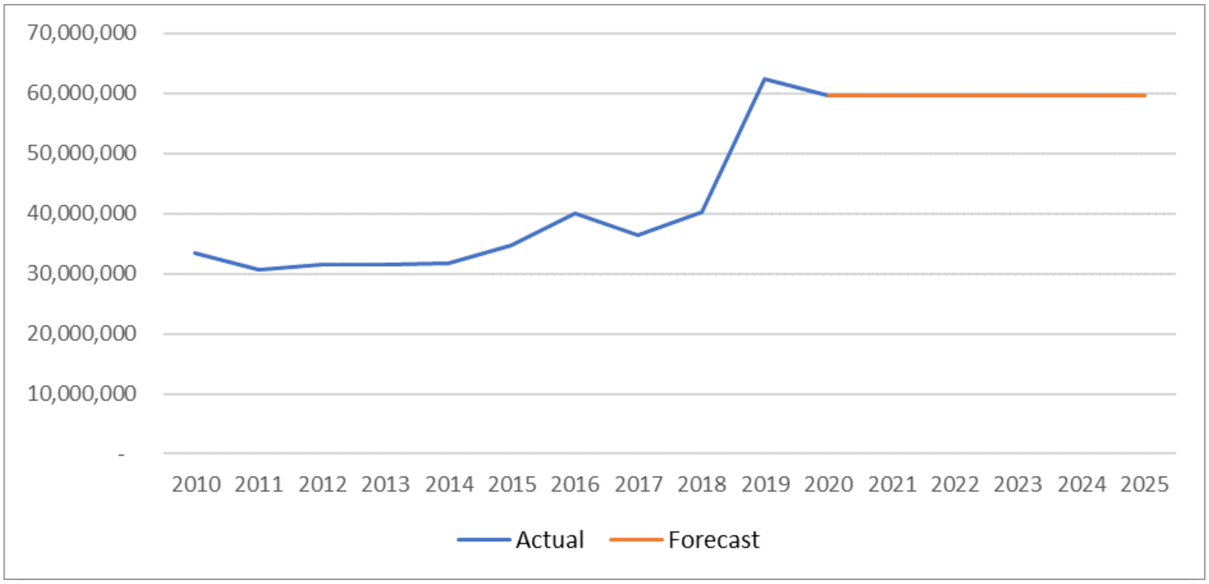

Figure 13 Actual vs Normalized R6

The R6 class has one customer and is expected to persist with one customer through 2025.

7 WEATHER SENSITIVITY

This section provides alternate low forecasts for scenarios with mild winters and high forecasts for cold winters. The low forecast uses the warmest winter in the past 10 years, which was 3,335 HDD (at 18°C) in 2012. The high forecast uses the coldest winter in the past 10 years, 4,306 HDD in 2014. The derived 18°C HDD forecast temperatures from 2021 to 2025 are provided with the normal forecast for reference. Forecast and actual HDDs from 2011 to 2020 are provided in Table 13.

Low Forecast	HDD	3,335.0	3,335.0	3,335.0	3,335.0	3,335.0
	2020 Actual	**2021 Forecast**	**2022 Forecast**	**2023 Forecast**	**2024 Forecast**	**2025 Forecast**
R1 Residential	16,843,918	16,638,397	17,206,172	17,793,016	18,399,563	19,026,465
R1 Industrial	2,103,134	2,020,104	2,128,875	2,242,801	2,362,107	2,487,032
R1 Commercial	5,008,664	5,175,763	5,339,739	5,508,696	5,682,780	5,862,143
R2 Seasonal	785,475	1,305,829	1,261,308	1,218,305	1,176,768	1,136,647
R3	1,372,226	1,398,790	1,337,070	1,282,294	1,233,267	1,189,065
R4	1,556,748	1,792,148	1,952,899	2,128,069	2,318,951	2,526,955
R5	554,438	693,203	693,203	693,203	693,203	693,203
R6	59,599,950	59,599,950	59,599,950	59,599,950	59,599,950	59,599,950
Total	**87,824,554**	**88,624,184**	**89,519,217**	**90,466,333**	**91,466,589**	**92,521,461**

Table 32 Low HDD Forecast

Normal Forecast	HDD	3,786.7	3,783.9	3,781.2	3,778.5	3,775.7
	2020 Actual	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast
R1 Residential	16,843,918	18,000,822	18,601,223	19,221,294	19,861,668	20,522,997
R1 Industrial	2,103,134	2,248,154	2,364,079	2,485,405	2,612,369	2,745,218
R1 Commercial	5,008,664	5,616,718	5,789,736	5,967,885	6,151,312	6,340,168
R2 Seasonal	785,475	1,305,829	1,261,308	1,218,305	1,176,768	1,136,647
R3	1,372,226	1,452,982	1,388,606	1,331,446	1,280,263	1,234,092
R4	1,556,748	1,792,148	1,952,899	2,128,069	2,318,951	2,526,955
R5	554,438	693,203	693,203	693,203	693,203	693,203
R6	59,599,950	59,599,950	59,599,950	59,599,950	59,599,950	59,599,950
Total	**87,824,554**	**90,709,805**	**91,651,004**	**92,645,557**	**93,694,483**	**94,799,231**

Table 33 Normal HDD Forecast

High Forecast	HDD	4,306.0	4,306.0	4,306.0	4,306.0	4,306.0
	2020 Actual	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast
R1 Residential	16,843,918	19,532,165	20,186,296	20,862,075	21,560,209	22,281,433
R1 Industrial	2,103,134	2,517,695	2,643,974	2,776,022	2,914,089	3,058,435
R1 Commercial	5,008,664	6,110,836	6,298,420	6,491,580	6,690,480	6,895,285
R2 Seasonal	785,475	1,305,829	1,261,308	1,218,305	1,176,768	1,136,647
R3	1,372,226	1,522,244	1,455,078	1,395,467	1,342,113	1,294,009
R4	1,556,748	1,792,148	1,952,899	2,128,069	2,318,951	2,526,955
R5	554,438	693,203	693,203	693,203	693,203	693,203
R6	59,599,950	59,599,950	59,599,950	59,599,950	59,599,950	59,599,950
Total	**87,824,554**	**93,074,070**	**94,091,127**	**95,164,670**	**96,295,763**	**97,485,917**

Table 34 High HDD Forecast

The graph below displays total forecast consumption for the three scenarios. The majority of consumption is not weather-sensitive so the range does not vary considerably on a total consumption basis.

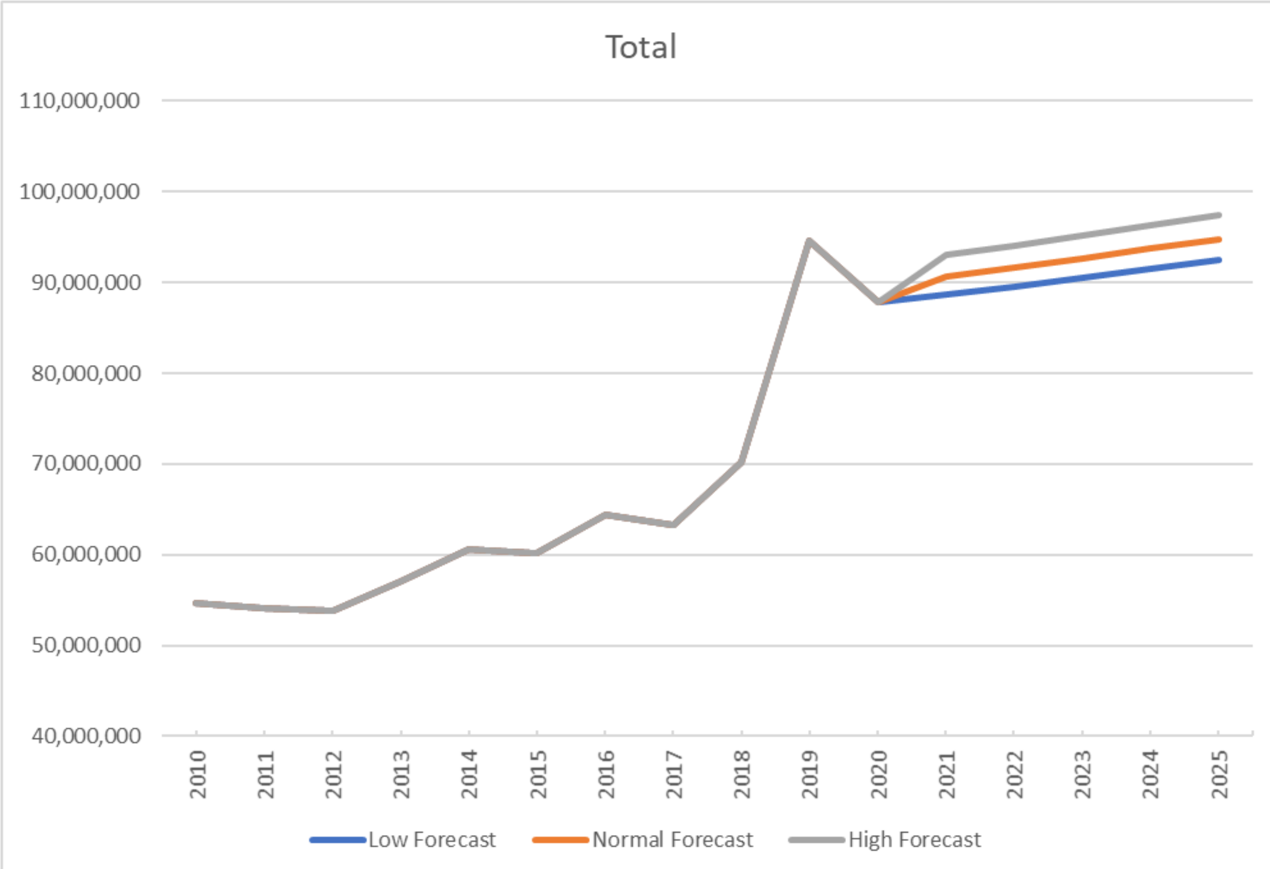

Figure 14 Weather Sensitivity – Total Consumption

Consumption forecasts for only largest weather-sensitive class, R1 Residential, are displayed in the following graph. Note the y-intercept is non-zero in each graph.

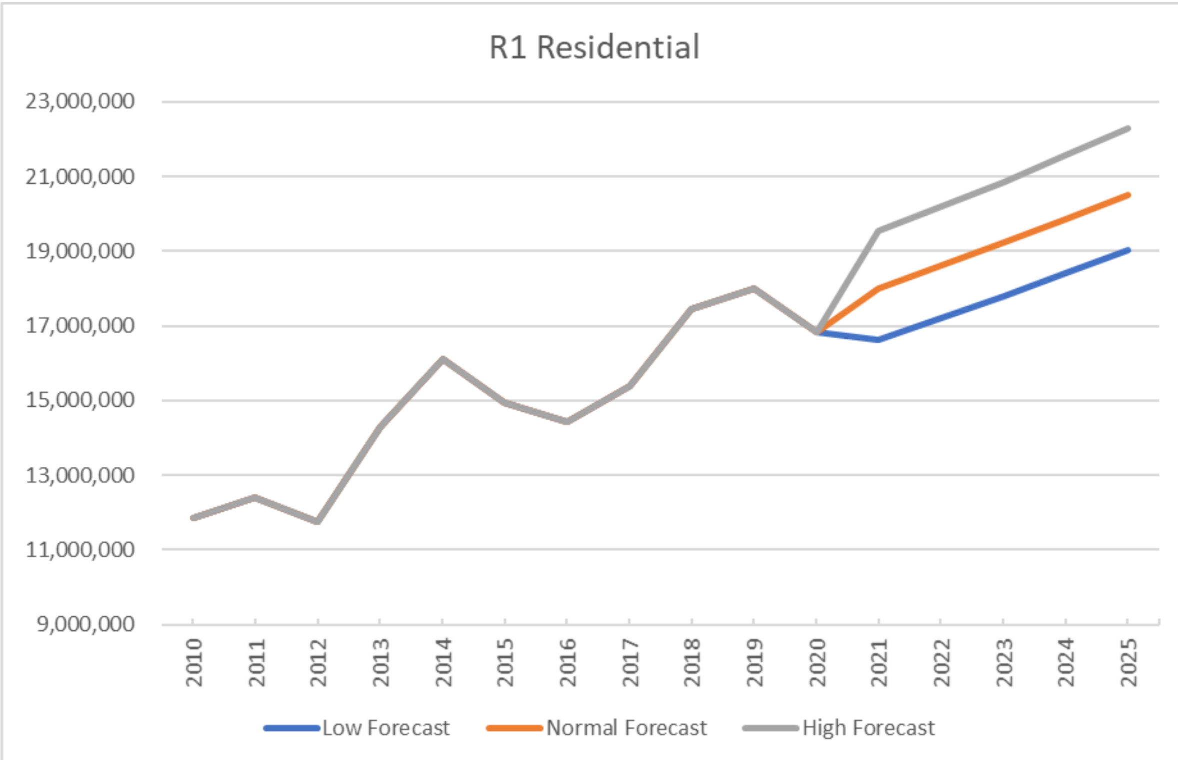

Figure 15 Weather Sensitivity – R1 Residential

15. Appendix F - EPCOR Aylmer Performance Metrics Scorecard

1. Cost Effectiveness	Performance Categories	Intent of Measures	Measures	Sample	2020
1. Cost Effectiveness	Policies & Procedures	Demonstrates consideration of alternate Enbridge rates	Annual rate review	C	C
	Price Effectiveness	Demonstrates local production a competitive option	Premium to system gas alternative	+/-%	**Well gas: +80%** **Lake gas: -5%**
2. Reliability & Security of Supply	**Performance Categories**	**Intent of Measures**	**Measures**	**Sample**	**2020**
2. Reliability & Security of Supply	Design Day	Demonstrates ENGPL ability to procure transportation assets required to meet design day demand	1. Acquired assets to meet design day	%	100%
			2. Enbridge Overrun Charges	$	$0
	Coordination	Demonstrates ENGPL ability to invest in capital distribution required to meet design day demand	Monthly meetings between gas supply & engineering operations	12/yr	4
	Communication	Ensure ongoing communications	Communication to ratepayers re material bill impacts	C	C
	Diversity	Demonstrate the diversity of the portfolio	1. % Firm local gas flow	%	95%
			2. Local production as % of system gas	%	37.08%
	Reliability	Demonstrate the reliability of the portfolio	1. Days failed to deliver to customers	#	0
			2.Days customer interrupted	#	0
	Performance Categories	**Intent of Measures**	**Measures**	**Sample**	**2020**
3. Public Policy	Supporting Policy	Reports public policy in ENGLP supply plan	1.Community expansion	C	C
			2. FCC	C	C
			3. RNG	C	N/A
			4. DSM	C	N/A